Attachment 2.1-6

Notice of Preliminary Determination of Compliance (PDOC)

Project Number C1011099: Henrietta Peaker Project (01-AFC-18)

San Joaquin Valley
Air Pollution Control District

September 6, 2001

Doug Wheeler
GWF Energy, LLC
4300 Railroad Avenue
Pittsburg, CA 94565

Re: Notice of Preliminary Determination of Compliance (PDOC)
Project Number: C1011099 – Henrietta Peaker Project (01-AFC-18)

Dear Mr. Wheeler:

Enclosed for your review and comments is the District's preliminary determination of compliance (PDOC) for GWF Energy, LLC – Henrietta Peaker Project, for the installation of a nominal 93.8 MW simple cycle power plant to be located at NW ¼ Section 34, Township 19 South, Range 19 East – Mount Diablo Base Meridian in Kings County.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Errol Villegas of Permit Services at (559) 230-5906.

Sincerely,

Seyed Sadredin
Director of Permit Services

SS/EV
Enclosures
c: David Warner, Permit Services Manager
Mark Kehoe, GWF Energy LLC.

DETERMINATION OF COMPLIANCE EVALUATION

Henrietta Peaker Project
California Energy Commission
Application for Certification Docket #: 01-AFC-18

Facility Name:	GWF Energy, LLC – Henrietta Peaker Power Plant
Mailing Address:	4300 Railroad Avenue Pittsburg, CA 94565
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Other Contact:	Mark Kehoe
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E-Mail:	mkehoe@gwfpower.com
Engineer:	Errol Villegas, Air Quality Engineer
Lead Engineer:	Dave Warner, Permit Services Manager
Date:	September 4, 2001
Project #:	C1011099
Application #'s:	C-3929-1-0 , C-3929-2-0, and C-3929-3-0
Submitted:	August 27, 2001

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I. PROPOSAL:

GWF Energy, LLC – Henrietta Peaker Power Plant hereinafter referred to as "Henrietta Peaker Project" is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "peaking" electrical power generation facility. The Henrietta Peaker Project will be a simple cycle power generation facility consisting of two natural gas fired combustion turbine generators (CTGs), with a nominal output of 93.8 megawatts (MW) electrical power, a 397 hp diesel-fired emergency IC engine, and associated facilities. The project will interconnect to the PG&E Henrietta Substation through a 550 foot, 70 kilovolt (kV) transmission line.

The Henrietta Peaker Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

II. APPLICABLE RULES:

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 2010 Permits Required (12/17/92)
Rule 2201 New and Modified Stationary Source Review (8/20/98)
Rule 2520 Federally Mandated Operating Permits (6/15/95)
Rule 2540 Acid Rain Program (11/13/97)
Rule 4001 NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines
Rule 4101 Visible Emissions (12/17/92)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4202 Particulate Matter Emission Rate (12/17/92)
Rule 4701 Internal Combustion Engines (11/12/98)
Rule 4703 Stationary Gas Turbines (10/16/97)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 8010 Fugitive Dust Administrative Requirements for Control of Fine Particulate Matter (4/25/96)
Rule 8020 Fugitive Dust Requirements for Control of Fine Particulate Matter (PM-10) From Construction, Demolition, Excavation, and Extraction Activities (4/25/96)
CH&S Code, Sections 41700, 42301.6 (School Notice), and 44300 (Air Toxic "Hot Spots")

III. PROJECT LOCATION:

NW ¼ Section 34, Township 19 South, Range 19 East – Mount Diablo Base Meridian on Assessor's Parcel Number 027-190-065.

The site is located on the eastern side of 25th Avenue, approximately one mile south of State Route (SR) 198, in Kings County. The proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

The proposed facility will consist of two natural gas-fired General Electric (GE) Model LM6000 PC Sprint combustion turbine generators (CTGs), each equipped with a water spray premixed combustion system, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, and associated support equipment and a 397 hp Caterpillar Model 3306 diesel-fired emergency IC engine powering a 250 kW generator. Each CTG system will consist of a stationary, heavy duty, industrial CTG, designed to use natural gas to produce electricity at a nominal output of 46.9 MW for each CTG. The total facility nominal output will be 93.8 MW. No cooling towers or heat recovery steam generators (HRSGs) will be installed. The applicant has not proposed any black start equipment.

The CTGs will operate during periods of peak electricity demand. Peak electricity demand periods typically occur during daylight hours in the second and third quarters of the calendar year, but can also occur during other periods when unusual temperature extremes cause unseasonably high electricity demand or when other electricity resource constraints reduce the amount of power otherwise available to the grid. This facility could operate during any of these periods.

The facility has proposed an operating scenario of 8,000 hours of full load operation per year with 300 total startups and shutdown events. GWF does not wish to be restricted to a specific number of hours of operation and startup/shutdown events per quarter. Actual emissions from the facility will vary depending on electricity demand from California. A hypothetical operating scenario has been developed for purposes of demonstrating that the project will comply with SJVAPCD emission offset requirements with the ERC's that have already been obtained for this project.

C-3929-1-0 and C-3929-2-0 Henrietta Peaker Project – Hypothetical Operating Scenario					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startups/Shutdown Events	50	100	100	50	300
Number of Full Load Hours	2,000	2,000	2,000	2,000	8,000

IV. PROCESS DESCRIPTION (Continued):

The CTGs will utilize water injection, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 3.6 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 6.0 ppmvd @ 15% O_2
SO_X: 0.00071 lb/MMBtu
PM_{10}: 3.3 lb/hr

Continuous emissions monitoring systems (CEM's) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

V. EQUIPMENT LISTING:

C-3929-1-0: 46.9 MW nominally rated Simple-Cycle Peak-Demand Power Generating System #1 consisting of a General Electric Model LM6000 natural gas-fired Combustion turbine Generator with water spray premixed combustion systems, served by a selective catalytic reduction (SCR) system with ammonia injection and an oxidation catalyst.

C-3929-2-0: 46.9 MW nominally rated Simple-Cycle Peak-Demand Power Generating System #1 consisting of a General Electric Model LM6000 natural gas-fired Combustion turbine Generator with water spray premixed combustion systems, served by a selective catalytic reduction (SCR) system with ammonia injection and an oxidation catalyst.

C-3929-3-0: 397 hp Caterpillar Model 3306 diesel-fired emergency IC engine powering a 250 kW generator.

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

C-3929-1-0 and C-3929-2-0

Each CTG will be equipped with water spray premixed combustion systems and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO & VOC catalyst. The use of water injection and a SCR system with ammonia injection can achieve a NO_X emission rate of 3.6 ppmvd @ 15% O_2. CO emissions of 6 ppmvd @ 15% O_2 and VOC emissions of 2 ppmvd @ 15% O_2 have been demonstrated with the use of an oxidation catalyst [(1)].

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

VI. EMISSION CONTROL TECHNOLOGY EVALUATION (Continued):

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2). This type of control device is also somewhat effective for controlling VOC emissions by a similar chemical reaction to that of carbon monoxide.

C-3929-3-0

The engine will be equipped with:

[X] Turbocharger
[X] Intercooler/aftercooler
[X] Positive Crankcase Ventilation (PCV) or 90% efficient control device
[X] Low (0.05%) sulfur diesel

VI. EMISSION CONTROL TECHNOLOGY EVALUATION (Continued):

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[2]

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

The PCV system reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

The use of low sulfur (0.05% by weight sulfur maximum) diesel fuel reduces SO_X emissions by approximately 90% from standard diesel fuel.

VII. CALCULATIONS:

A. Assumptions

C-3929-1-0 and C-3929-2-0

- BACT emission concentration limits of 3.6 ppmvd @ 15% O_2, 6.0 ppmvd @ 15% O_2, and 2.0 ppmvd @ 15% O_2 are proposed for NO_X, CO, and VOC, respectively, at all operating loads (except during start-ups and shutdowns).

- The applicant proposes NO_X, CO and VOC mass emission rates of 5.9 lb/hr, 2.44 lb/hr and 0.33 lb/hr, respectively, at 100% load and 63 °F (average ambient temperature).

- The applicant proposes a PM_{10} mass emission rate of 3.3 lb/hr for each CTG based on the vendor's guarantee for both the filterable and condensable portions of PM_{10}.

- A SO_X emissions rate of 0.33 lb/hr was calculated using the CTGs maximum heat input of 459.6 MMBtu/hr (@ 100% load and 63 °F) by performing a mass balance assuming 1,000 Btu/scf (hhv) for natural gas, and a natural gas sulfur content of 0.25 gr S/100 scf.

  (0.25 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1000 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00071 lb/MMBtu

[2] From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

VII. CALCULATIONS (Continued):

- Maximum daily emissions for each CTG were estimated assuming 100% capacity, an ambient temperature of 63 °F, one 1-hour startup/shutdown event, followed by 23 hours of full load operation.
- SO_X emissions are proportional to fuel use, so the maximum daily emission rate is based on 24 hours of operation, @ 100% capacity and 63 °F.
- Quarterly emissions are based on the following hypothetical operating schedule:

C-3929-1-0 and C-3929-2-0 Henrietta Peaker Project – Hypothetical Operating Scenario (Repeated from P. 2)					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startups/Shutdown Events	50	100	100	50	300
Number of Full Load Hours	2,000	2,000	2,000	2,000	8,000

C-3929-3-0

- Diesel F factor is 9,190 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher Heating Value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day and 200 hours per year of operation. (maximum non-emergency use)

B. Emission Factors

C-3929-1-0 and C-3929-2-0

The maximum air contaminant mass emission rates (lb/hr), concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates estimated by the manufacturer (see Attachment B for manufacturer's emissions data) for the proposed CTG's are summarized below:

VII. CALCULATIONS (Continued):

Maximum Emission Rates and Concentrations (@ 100% Load & 63 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	5.9	2.44	0.33	3.3	0.33	6.25
ppmvd @ 15% O_2 limits	3.6	6.0	2.0	--	--	10.0

Startup and Shutdown Emissions (1-hour duration)*					
	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)	PM_{10} (lb/event)	SO_X (lb/event)
Mass Emission Rate (per turbine)	7.7	7.7	0.68	3.14	N/A[3]

* Pursuant to the turbine vendor, "A start-up/shutdown event is estimated to be completed in 10 minutes; however, for simplification the emissions for a start-up/shutdown event are calculated as hourly emissions with the 10 minute start-up emissions being added to 50 minutes of baseload operating emissions."

C-3929-3-0

For the new emergency IC engine, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the sulfur content in the diesel fuel (0.05% sulfur).

IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	5.09	Engine Manufacturer
CO	1.13	Engine Manufacturer
VOC	0.14	Engine Manufacturer
PM_{10}	0.13	Engine Manufacturer
*SO_X	0.171	Mass Balance Equation Below

$$^{*}0.05\% \times \frac{7.1\,lb \cdot fuel}{gallon} \times \frac{2\,lb \cdot SO_2}{1\,lb \cdot S} \times \frac{1\,gal}{137{,}000\,Btu} \times \frac{1\,hp\,input}{0.35\,hp\,out} \times \frac{2{,}542.5\,Btu}{hp \cdot hr} \times \frac{453.6\,g}{lb} = 0.171\,\frac{g\,SOx}{hp \cdot hr}$$

C. <u>Potential to Emit (PE):</u>

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. The criteria pollutant potentials to emit for each emission unit is presented below:

[3] SO_X emissions during startups and shutdowns are always lower than maximum hourly emissions as SO_X emissions are proportional to fuel flow.

VII. CALCULATIONS (Continued):

C-3929-1-0 and C-3929-2-0

1. Maximum Hourly Emissions

The maximum hourly emissions for NO_X, CO, and VOC from each CTG will occur when the unit undergoes one startup/shutdown event. The maximum hourly emissions are summarized in the table below:

Maximum Hourly Emissions (C-3929-1-0 and C-3929-2-0)				
	Startup Emissions (lb/event)	Turbine #1 Emissions	Turbine #2 Emissions	Maximum Hourly Emissions for Both Turbines
NO_X	7.7 lb	7.7 lb	7.7 lb	15.4 lb/hr
CO	7.7 lb	7.7 lb	7.7 lb	15.4 lb/hr
VOC	0.68 lb	0.68 lb	0.68 lb	1.36 lb/hr
PM_{10}	N/A[4]	3.3 lb	3.3 lb	6.6 lb/hr
SO_X	N/A[4]	0.33 lb	0.33 lb	0.66 lb/hr
NH_3	N/A[4]	6.25 lb	6.25 lb	12.5 lb/hr

2. Maximum Daily PE

The maximum daily emissions occur when each CTG undergoes one 1-hour startup/shutdown period, followed by 23 hours of operation at 100% load. The results are summarized in the table below:

Maximum Daily Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	DEL (per CTG)	Combined DEL for 2 CTGs
NO_X	7.7 lb	5.9 lb/hr	141.6 lb/day	143.4 lb/day	286.8 lb/day
CO	7.7 lb	2.44 lb/hr	58.6 lb/day	63.8 lb/day	127.6 lb/day
VOC	0.68 lb	0.33 lb/hr	7.9 lb/day	8.3 lb/day	16.6 lb/day
PM_{10}	N/A[5]	3.3 lb/hr	79.2 lb/day	79.2 lb/day	158.4 lb/day
SO_X	N/A[5]	0.33 lb/hr	7.9 lb/day	7.9 lb/day	15.8 lb/day
NH_3	N/A[5]	6.25 lb/hr	150.0 lb/day	150.0 lb/day	300.0 lb/day

[4] The maximum hourly emissions for this pollutant occur when each CTG operates at 100% load for 1 hour.
[5] Maximum daily emissions for this pollutant occur when each CTG is operated at 100% load for 24 hr/day.

VII. CALCULATIONS (Continued):

3. *Maximum Quarterly PE*

Maximum quarterly emissions for each unit will be determined by the following equation:

$$PE\left(\frac{lb}{qtr}\right) = \left(\frac{events}{qtr} \times \text{startup/shutdown events}\left(\frac{lb}{event}\right)\right) + \left(2{,}000\frac{hr}{qtr} \times \text{mass emission rate}\left(\frac{lb}{hr}\right)\right)$$

Quarters 1 and 4

The maximum emissions from each CTG during the first and fourth quarters will occur when each unit undergoes fifty (50) startup/shutdown events and 2,000 hours of operation at 100% load, as summarized in the tables below:

First Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTGs
NO_X	7.7 lb	5.9 lb/hr	11,800 lb/qtr	12,185 lb/qtr	24,370 lb/qtr
CO	7.7 lb	2.44 lb/hr	4,880 lb/qtr	5,265 lb/qtr	10,530 lb/qtr
VOC	0.68 lb	0.33 lb/hr	660 lb/qtr	694 lb/qtr	1,388 lb/qtr
PM_{10}	N/A[6]	3.3 lb/hr	6,600 lb/qtr	6,600 lb/qtr	13,200 lb/qtr
SO_X	N/A[6]	0.33 lb/hr	660 lb/qtr	660 lb/qtr	1,320 lb/qtr
NH_3	N/A[6]	6.25 lb/hr	12,500 lb/qtr	12,500 lb/qtr	25,000 lb/qtr

Fourth Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTGs
NO_X	7.7 lb	5.9 lb/hr	11,800 lb/qtr	12,185 lb/qtr	24,370 lb/qtr
CO	7.7 lb	2.44 lb/hr	4,880 lb/qtr	5,265 lb/qtr	10,530 lb/qtr
VOC	0.68 lb	0.33 lb/hr	660 lb/qtr	694 lb/qtr	1,388 lb/qtr
PM_{10}	N/A[6]	3.3 lb/hr	6,600 lb/qtr	6,600 lb/qtr	13,200 lb/qtr
SO_X	N/A[6]	0.33 lb/hr	660 lb/qtr	660 lb/qtr	1,320 lb/qtr
NH_3	N/A[6]	6.25 lb/hr	12,500 lb/qtr	12,500 lb/qtr	25,000 lb/qtr

[6] Maximum quarterly emissions for this pollutant occur when each CTG is operated at 100% load for 2,000 hr/qtr.

VII. CALCULATIONS (Continued):

Quarters 2 and 3

The maximum emissions from each CTG during the second and third quarters will occur when each unit undergoes one hundred (100) startup/shutdown events and 2,000 hours of operation at 100% load, as summarized in the tables below:

Second Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTGs
NO_X	7.7 lb	5.9 lb/hr	11,800 lb/qtr	12,570 lb/qtr	25,140 lb/qtr
CO	7.7 lb	2.44 lb/hr	4,880 lb/qtr	5,650 lb/qtr	11,300 lb/qtr
VOC	0.68 lb	0.33 lb/hr	660 lb/qtr	728 lb/qtr	1,456 lb/qtr
PM_{10}	N/A[7]	3.3 lb/hr	6,600 lb/qtr	6,600 lb/qtr	13,200 lb/qtr
SO_X	N/A[7]	0.33 lb/hr	660 lb/qtr	660 lb/qtr	1,320 lb/qtr
NH_3	N/A[7]	6.25 lb/hr	12,500 lb/qtr	12,500 lb/qtr	25,000 lb/qtr

Third Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTGs
NO_X	7.7 lb	5.9 lb/hr	11,800 lb/qtr	12,570 lb/qtr	25,140 lb/qtr
CO	7.7 lb	2.44 lb/hr	4,880 lb/qtr	5,650 lb/qtr	11,300 lb/qtr
VOC	0.68 lb	0.33 lb/hr	660 lb/qtr	728 lb/qtr	1,456 lb/qtr
PM_{10}	N/A[7]	3.3 lb/hr	6,600 lb/qtr	6,600 lb/qtr	13,200 lb/qtr
SO_X	N/A[7]	0.33 lb/hr	660 lb/qtr	660 lb/qtr	1,320 lb/qtr
NH_3	N/A[7]	6.25 lb/hr	12,500 lb/qtr	12,500 lb/qtr	25,000 lb/qtr

4. Maximum Annual PE

The maximum annual PE is merely the sum of the maximum quarterly PE calculated in section VII.C.3 of this document. The results are summarized in the table below:

[7] Maximum quarterly emissions for this pollutant occur when each CTG is operated at 100% load for 2,000 hr/qtr.

VII. CALCULATIONS (Continued):

Maximum Annual Emissions (each CTG)						
Quarter	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
1st (lb/qtr)	12,185	5,265	694	6,600	660	12,500
2nd (lb/qtr)	12,570	5,650	728	6,600	660	12,500
3rd (lb/qtr)	12,570	5,650	728	6,600	660	12,500
4th (lb/qtr)	12,185	5,265	694	6,600	660	12,500
Annual PE (lb/yr)	49,510	21,830	2,844	26,400	2,640	50,000

Maximum Annual Emissions (both CTGs)						
Quarter	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
1st (lb/qtr)	24,370	10,530	1,388	13,200	1,320	25,000
2nd (lb/qtr)	25,140	11,300	1,456	13,200	1,320	25,000
3rd (lb/qtr)	25,140	11,300	1,456	13,200	1,320	25,000
4th (lb/qtr)	24,370	10,530	1,388	13,200	1,320	25,000
Annual PE (lb/yr)	99,020	43,660	5,688	52,800	5,280	100,000

C-3929-3-0

5. Potential to Emit

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

$$PE_{NOx} = (5.09\ \text{g/hp}\cdot\text{hr}) * (397\ \text{hp}) \div (453.6\ \text{g/lb})$$
$$= 4.45\ \text{lb } NO_X/\text{hr}$$

$$= (5.09\ \text{g/hp}\cdot\text{hr}) * (397\ \text{hp}) \div (453.6\ \text{g/lb}) * (24\ \text{hr/day})$$
$$= 106.9\ \text{lb } NO_X/\text{day}$$

$$= (5.09\ \text{g/hp}\cdot\text{hr}) * (397\ \text{hp}) \div (453.6\ \text{g/lb}) * (50\ \text{hr/year})$$
$$= 223\ \text{lb } NO_X/\text{qtr}$$

$$= (5.09\ \text{g/hp}\cdot\text{hr}) * (397\ \text{hp}) \div (453.6\ \text{g/lb}) * (200\ \text{hr/year})$$
$$= 891\ \text{lb } NO_X/\text{year}$$

$$PE_{CO} = (1.13\ \text{g/hp}\cdot\text{hr}) * (397\ \text{hp}) \div (453.6\ \text{g/lb})$$
$$= 0.99\ \text{lb CO/hr}$$

$$= (1.13\ \text{g/hp}\cdot\text{hr}) * (397\ \text{hp}) \div (453.6\ \text{g/lb}) * (24\ \text{hr/day})$$
$$= 23.7\ \text{lb CO/day}$$

$$= (1.13\ \text{g/hp}\cdot\text{hr}) * (397\ \text{hp}) \div (453.6\ \text{g/lb}) * (50\ \text{hr/year})$$
$$= 50\ \text{lb CO/qtr}$$

VII. CALCULATIONS (Continued):

$= (1.13\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (200\ hr/year)$
$= 198\ lb\ CO/year$

$PE_{VOC} = (0.14\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb)$
$= 0.12\ lb\ VOC/hr$

$= (0.14\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (24\ hr/day)$
$= 2.9\ lb\ VOC/day$

$= (0.14\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (50\ hr/year)$
$= 6\ lb\ VOC/qtr$

$= (0.14\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (200\ hr/year)$
$= 25\ lb\ VOC/year$

$PE_{PM10} = (0.13\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb)$
$= 0.11\ lb\ PM_{10}/hr$

$= (0.13\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (24\ hr/day)$
$= 2.7\ lb\ PM_{10}/day$

$= (0.13\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (50\ hr/year)$
$= 6\ lb\ PM_{10}/qtr$

$= (0.13\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (200\ hr/year)$
$= 23\ lb\ PM_{10}/year$

$PE_{SOx} = (0.171\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb)$
$= 0.15\ lb\ SO_X/hr$

$= (0.171\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (24\ hr/day)$
$= 3.6\ lb\ SO_X/day$

$= (0.171\ g/hp\cdot hr) * (397\ hp) \div (453.6\ g/lb) * (50\ hr/year)$
$= 8\ lb\ SO_X/qtr$

$= (0.171\ g/hp\cdot\text{-}hr) * (397\ hp) \div (453.6\ g/lb) * (200\ hr/year)$
$= 30\ lb\ SO_X/year$

VII. CALCULATIONS (Continued):

Potential to Emit (PE) (C-3929-3-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	4.45	106.9	223	891
CO	0.99	23.7	50	198
VOC	0.12	2.9	6	25
PM_{10}	0.11	2.7	6	23
SO_X	0.15	3.6	8	30

D. Increase in Permitted Emissions (IPE):

1. Daily Increase in Permitted Emissions

For new emissions units, the daily IPE is the proposed daily PE for that emissions unit. Please refer to Sections VII.C.2 and VII.C.5 of this document for the maximum daily PE for each unit.

2. Quarterly Increase in Permitted Emissions

For new emissions units, the quarterly IPE is the proposed quarterly PE for that emissions unit. Please refer to section VII.C.3 and VII.C.5 of this document for the maximum quarterly PE for each unit.

3. Annual Increase in Permitted Emissions

For new emissions units, the annual IPE is the proposed annual PE for that emissions unit. Please refer to section VII.C.4 and VII.C.5 of this document for the maximum annual PE for each unit.

4. Adjusted Increase in Permitted Emissions (AIPE)

The AIPE is used to determine if BACT is required for emission units which are being modified. District Rule 2201, section 4.3 defines AIPE as the difference between an emission unit's post-project potential to emit (PE2) and the emission unit's Historically Adjusted Potential to Emit (HAPE): AIPE = PE2 – HAPE. Since these are new units and are not being modified, the BACT requirements are based on the daily IPE calculated above. Therefore the AIPE will not be calculated.

VII. CALCULATIONS (Continued):

5. Stationary Source Increase in Permitted Emissions (SSIPE)

Since this is a new stationary source, the Stationary Source Project Increase in Permitted Emissions (SSIPE) is equal to the Post-Project Stationary Source Potential to Emit (SSPE2). The SSIPE is summarized in the table below:

SSIPE (lb/yr)						
Permit Unit	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
C-3929-1-0	49,510	21,830	2,844	26,400	2,640	50,000
C-3929-2-0	49,510	21,830	2,844	26,400	2,640	50,000
C-3929-3-0	891	198	25	23	30	0
Total	99,911	43,858	5,713	52,823	5,310	100,000

6. Contemporaneous Increase in Permitted Emissions (CIPE)

Calculating CIPE is required for existing Major Sources to determine if the current project will increase emissions above Title I Modification thresholds. Since this facility is not an existing Major Source, the CIPE will not be calculated.

E. <u>Facility Emissions:</u>

1. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

2. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post-project Stationary Source Potential to Emit (SSPE2) is the post-project annual PE of all units at the Stationary Source.

VII. CALCULATIONS (Continued):

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Pre-project SSPE (SSPE1)	0	0	0	0	0	0
C-3929-1-0	49,510	21,830	2,844	26,400	2,640	50,000
C-3929-2-0	49,510	21,830	2,844	26,400	2,640	50,000
C-3929-3-0	891	198	25	23	30	0
Post-project SSPE (SSPE2)	99,911	43,858	5,713	52,823	5,310	100,000

3. *Baseline Emissions (BE)*

Baseline Emissions calculations are required to determine the quantity of offsets for facilities with an increase in stationary source emissions and a pre-project Stationary Source Potential to Emit (SSPE1) greater than emission offset thresholds. Since this is a new facility and the SSPE1 is less than emission offset thresholds, Baseline Emissions calculations are not necessary.

VIII. COMPLIANCE:

Rule 1080 *Stack Monitoring (12/17/92)*

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEM's), and specifies performance standards for the equipment and administrative requirements for record keeping, reporting, and notification. The facility will be equipped with operational CEM's for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

VIII. COMPLIANCE (Continued):

- Permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- Permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions; nature and cause of excess (averaging period used for data reporting shall correspond to the averaging period for each respective emission standard); corrective actions taken and preventive measures adopted; applicable time and date of each period during a CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Rule 1081 *Source Sampling (12/16/93)*

This Rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

<u>Proposed Rule 1081 Conditions</u>:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure the NO_X, CO, and VOC emission limits (lb/hr and ppmvd @ 15% O_2) shall be conducted within 60 days of initial operation of the CTG and at least once every twelve months thereafter. [District Rule 1081]

- Source testing to measure the PM_{10} emission limit (lb/hr), the natural gas sulfur content limit, and the ammonia emission limit shall be conducted within 60 days of initial operation and at least once every twelve months thereafter. [District Rule 1081]

VIII. COMPLIANCE (Continued):

- Source testing of startup NO_X, CO, VOC, and PM_{10} mass emission rates shall be conducted for one of the gas turbine engines (C-3929-1 or C-3929-2) upon initial operation and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used PM10: EPA Method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA Method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA Method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

Rule 2010 *Permits Required (12/17/92)*

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, GWF Energy LLC is complying with the requirements of this Rule.

Rule 2201 *New and Modified Stationary Source Review Rule (08/20/01)*

A. BACT:

1. BACT Applicability

Pursuant to Sections 4.1.1 and 4.1.2, BACT shall be applied to a new, relocated, or modified emissions unit if the new or relocated unit has a Potential to Emit (PE) exceeding two pounds in any one day or the modified emissions unit results in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2 lb/day for NO_X, CO, VOC, PM_{10}, or SO_X. For CO emissions, the CO Post-project Stationary Source Potential to Emit (SSPE2) must also exceed 200,000 lb/year to trigger BACT.

VIII. COMPLIANCE (Continued):

As seen in Section VII.D of this evaluation, the applicant is proposing to install three new emissions units with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day, but BACT is not triggered for CO emissions since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.E.2 of this document.

The PE of ammonia is greater than two pounds per day. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

2. BACT Guidance

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. The District BACT Clearinghouse recently included a new BACT Guideline (3.4.8) applicable to the turbine installations [Simple Cycle Gas Fired Turbines less than 50 MW, Powering an Electrical Generation Operation]. (See Attachment C) BACT Guideline 3.1.2, which also appears in Attachment C of this report, covers diesel-fired emergency IC engines greater than or equal to 175 hp and less than 400 hp.

3. BACT Summary:

C-3929-1-0 and C-3929-2-0

BACT has been satisfied by the following:

NO_X: 3.6 ppmv @ 15% O2 (3 hour rolling average) using water injection, SCR with ammonia injection, an oxidation catalyst and natural gas fuel - except during startup/shutdown.

VOC: 2.0 ppmv @ 15% O2 (3 hour rolling average) - except during startup/shutdown.

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: Natural gas with a sulfur content of 0.25 gr/100 scf

C-3929-3-0

BACT has been satisfied by the following:

NO_X: Certified NO_X emissions of 5.09 g/hp·hr

VIII. COMPLIANCE (Continued):

VOC: Positive Crankcase Ventilation (PCV)

PM_{10}: Certified PM_{10} emissions of 0.13 g/hp·hr

SO_X: Low-sulfur diesel fuel (500 ppmv sulfur or less) or Very Low-sulfur diesel fuel (15 ppmv or less) where available

4. Top-Down Best Available Control Technology (BACT) Analysis

For Permit Units C-3929-1-0 and -2-0 see Attachment D.

For Permit Unit C-3929-3-0 see Attachment E.

B. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in Section VII.E.2 of this document, the facility's SSPE2 is greater than the offset thresholds for NO_X and PM_{10} emissions. Therefore, offset calculations are necessary.

2. Quantity of Offsets Required:

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X and PM_{10} is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offset = [SSPE2 – offset threshold] ∗ Offset Ratio

Where, Offset Ratio = Distance or interpollutant ratio of Sections 4.8 and 4.13.3

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit unit C-3929-3-0 will be exempt from providing offsets and the emissions associated with this permit unit contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = [SSPE2 – (emergency equipment) – offset threshold] ∗ Offset Ratio

VIII. COMPLIANCE (Continued):

NO_X Offset Calculations:

NO_X SSPE2	= 99,911 lb/year
C-3929-3-0 (NO_X)	= 891 lb/year
NO_X offset threshold	= 20,000 lb/year

Offsets = [99,911 – (891) – 20,000]
= 79,020 lb/year

As discussed in Section VII.C.3, the hypothetical operating scenario for each turbine unit assumes 50 startup/shutdown events in the 1st and 4th Quarters and 100 startup/shutdown events occurring in the 2nd and 3rd Quarters. Calculating the appropriate quarterly emissions to be offset is as follows:

$PE_{1st\ Qtr}$ = [(7.7 lb NO_X/event) ∗ (50 event/1st qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] + [(7.7 lb NO_X/event) ∗ (50 event/1st qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] – [5,000 lb/1st qtr]
= 19,370 lbs of NO_X

$PE_{2nd\ Qtr}$ = [(7.7 lb NO_X/event) ∗ (100 event/2nd qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] + [(7.7 lb NO_X/event) ∗ (100 event/2nd qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] – [5,000 lb/2nd qtr]
= 20,140 lbs of NO_X

$PE_{3rd\ Qtr}$ = [(7.7 lb NO_X/event) ∗ (100 event/3rd qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] + [(7.7 lb NO_X/event) ∗ (100 event/3rd qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] – [5,000 lb/3rd qtr]
= 20,140 lbs of NO_X

$PE_{4th\ Qtr}$ = [(7.7 lb NO_X/event) ∗ (50 event/4th qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] + [(7.7 lb NO_X/event) ∗ (50 event/4th qtr) + (5.9 lb/hr) ∗ (2,000 hr/qtr)] – [5,000 lb/4th qtr]
= 19,370 lbs of NO_X

Assuming an offset ratio of 1.5: 1, the amount of NO_X ERC credits that need to be surrendered to the District is:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
29,055	30,210	30,210	29,055

The applicant has stated that the facility plans to use ERC certificates C-410-2, C-411-2, C-412-2, and S-1585-2 to offset the increases in NO_X emissions associated with this project. The above Certificates have available quarterly NO_X credits as follows:

VIII. COMPLIANCE (Continued):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-410-2	22,510	0	0	5,708
ERC #C-411-2	5,205	4,562	4,562	7,991
ERC #C-412-2	0	0	0	1,915
ERC #S-1585-2[8]	110,866	112,097	113,330	113,330
Total:	138,582	116,661	117,895	128,948

As seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 52,823 lb/year
C-3929-3-0 (PM_{10}) = 23 lb/year
PM_{10} offset threshold = 29,200 lb/year

Offsets = [52,823 – (23) – 29,200]
= 23,600 lb/year

Since the maximum annual emissions are equivalent to operating at normal baseload conditions, calculating the appropriate quarterly PM_{10} emissions to be offset is as follows: (= Annual offsets ÷ 4 qtrs)

$PE_{1st\ Qtr}$ = 5,900 lbs of PM_{10}
$PE_{2nd\ Qtr}$ = 5,900 lbs of PM_{10}
$PE_{3rd\ Qtr}$ = 5,900 lbs of PM_{10}
$PE_{4th\ Qtr}$ = 5,900 lbs of PM_{10}

Assuming an offset distance ratio of 1.5: 1, the amount of PM_{10} ERC credits that need to be surrendered to the District is:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
8,850	8,850	8,850	8,850

The applicant has stated that the facility plans to use ERC certificate C-0366-4 to offset the increases in PM_{10} emissions associated with this project. Certificate C-0366-4 has available quarterly PM_{10} credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-0366-4	5,699	5,087	7,081	6,732

[8] Project #S-1010808 to transfer ERC Certificate S-1585-2 from Occidental of Elk Hills to GWF Energy is currently in progress.

VIII. COMPLIANCE (Continued):

As seen above, the facility is lacking sufficient credits to fully offset the emissions increases for PM_{10}. As proposed by the applicant, in order to satisfy District offset requirements the applicant has proposed providing SO_X reductions in place of PM_{10} reductions. District Rule 2201 Section 4.13.3 allows such interpollutant substitutions provided the applicant shows that the substitution will not cause or contribute to the violation of an ambient air quality standard and that the appropriate interpollutant offset ratio is utilized.

Interpollutant Offset Ratio:

GWF Energy LLC, has proposed to provide SO_X credits to offset PM_{10} credits at a distance offset ratio of 1.5:1 and an interpollutant offset ratio of 1.4:1 (totaling a 1.9:1 ratio). In order for the District to approve interpollutant offsetting, the facility has to demonstrate that the emissions increases will not cause or contribute to a violation of an Ambient Air Quality Standard. Because the ambient PM_{10} concentrations in the San Joaquin Valley currently exceed the state and federal standards, the District is accepting a demonstration that the project will not cause PM_{10} ambient concentrations in excess of the significance criteria in Title 40 Code of Federal Regulations Part 51.165(b)(2). These thresholds are 1.0 $\mu g/m^3$ for the annual standard and 5.0 $\mu g/m^3$ for the 24 hour standard.

To support this interpollutant substitution ratio the District conducted an air quality modeling analysis to determine the impact of the increased PM_{10} emissions from this project on the ambient air quality standards. According to the modeling results, the project will not cause or contribute to a violation of any Air Quality Standards (See Attachment F). GWF also provided information from a memo dated August 8, 2001 from a Mr. David Deckman, of Sierra Research (See Attachment G). In the memo, a speciated linear rollback analysis using ambient monitoring data from Kings County is used to develop an interpollutant offset ratio for SO_X and PM_{10}. Based upon the above information, the District will accept GWF Energy's proposal and accept SO_X credits in place of PM_{10} credits at a 1.9:1 ratio.

To offset the remaining PM_{10} emissions:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining emissions: (already at a 1.5:1 ratio)	3,151	3,763	1,769	2,118
@ an additional 1.4:1 ratio	4,411	5,268	2,477	9,965

The facility has proposed to use the SO_X ERC certificate C-414-5 to offset the remaining increases in PM_{10} emissions. C-414-5 has available quarterly SO_X credits as follows:

VIII. COMPLIANCE (Continued):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-414-5	23,108	13,700	14,900	16,579

With ERC Certificate C-414-5, the facility should have sufficient emission reduction credits to fully offset the PM_{10} emissions associated with this project.

3. Actual Emission Reductions

There are no actual emissions reductions (AERs) proposed as a result of this application. AER = 0.

C. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Title I modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Modifications with SSPE1 below an offset threshold and SSPE 2 above an offset threshold on a pollutant by pollutant basis (Existing Facility - Offset Threshold Notification)
- New stationary sources with SSPE2 exceeding offset thresholds (New Facility - Offset Threshold Notification)
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination:

Major Source Determination					
	NO_X	CO	VOC	PM_{10}	SO_X
Post-project SSPE (SSPE2)	99,911	43,858	5,713	52,823	5,310
Major Source Threshold	100,000	200,000	100,000	140,000	140,000
Major Source?	No	No	No	No	No

As shown in the table above, the SSPE2 for every criteria pollutant for the facility is below the specific thresholds. Therefore, public noticing is not required for this project for new Major Source purposes because this facility is not becoming a new Major Source.

VIII. COMPLIANCE (Continued):

b. Title I Modification Notice Determination:

For facilities that are non-major sources prior to the modification, a Title I modification is triggered if the post project stationary source potential to emit (SSPE2) is increased to levels above the thresholds listed in Table 3-4 of District Rule 2201.

Title I Modification Determination (lb/year)					
	NO_X	CO	VOC	PM_{10}	SO_X
Post-project SSPE (SSPE2)	99,911	43,858	5,713	52,823	5,310
Title I Modification Threshold	100,000	200,000	100,000	140,000	140,000
Title I Modification?	No	No	No	No	No

As shown in the table above, the SSPE2 is not increased above the thresholds, therefore public noticing is not require for this project for Title I modification purposes.

c. PE Notification:

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the tables below.

Post-Project Potential to Emit: (C-3929-1-0)						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-3929-1-0	143.4	63.8	8.27	79.2	7.92	150
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	**Yes**	No	No	No	No	**Yes**

Post-Project Potential to Emit: (C-3929-2-0)						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-3929-2-0	143.4	63.8	8.27	79.2	7.92	150
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	**Yes**	No	No	No	No	**Yes**

VIII. COMPLIANCE (Continued):

Post-Project Potential to Emit: (C-3929-3-0)					
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)
C-3929-3-0	106.9	23.7	2.9	2.7	3.6
Threshold (lb/day)	100	100	100	100	100
Notification Required?	**Yes**	No	No	No	No

According to the tables above, permit units C-3929-1-0 and -2-0 will each have a Potential to Emit greater than 100 lbs/day for NO_X and NH_3 emissions, and permit unit C-3929-3-0 will have a Potential to Emit greater than 100 lbs/day for NO_X emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

d. Existing Facility - Offset Threshold Notification

This is not an existing facility. This section does not require a public notification.

e. New Facility - Offset Threshold Notification

New Stationary Sources with an SSPE2 exceeding the emission offset threshold level for one or more pollutants will require public noticing. As shown in Section VII.E.2 and discussed in Section VIII.B.1 (Rule 2201), offset thresholds for NO_X and PM_{10} emissions are exceeded with this project. Therefore, public noticing is required for offset purposes.

Since this is a new stationary source, the SSPE1 for all pollutants is below the offset thresholds. As shown in section VII.E.2 of this document, the SSPE2 for NO_x, VOC, and PM_{10} emissions will exceed the offset thresholds. Therefore, a public notification is required for NO_x, VOC, and PM_{10} emissions.

f. SSIPE Notification:

A notification is required for any permitting action that results in a SSSIPE of more than 20,000 lb/yr of any affected pollutant. As shown in section VII.D.5 of this document, the SSIPE for NO_X, CO, VOC, PM_{10}, and NH_3 will be more than 20,000 pounds per year. Therefore, a SSIPE notification is required for NO_X, CO, VOC, PM_{10}, and NH_3.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. PEs > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

VIII. COMPLIANCE (Continued):

C. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.17 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.17.1 and 3.17.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis.

C-3929-1-0 and C-3929-2-0 (Turbines)

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, and SO_X will consist of lb/day and/or emission factors.

- The NOx emissions shall not exceed 143.4 pounds per day.
- The NOx emissions during steady state operation shall not exceed 3.6 ppmvd @ 15% O_2 over a three hour averaging period. Steady-state period refers to any period that is not a start-up or shutdown period.
- The CO emissions shall not exceed 63.8 pounds per day.
- The CO emissions during steady state operation shall not exceed 6.0 ppmvd @ 15% O_2. Steady-state period refers to any period that is not a start-up or shutdown period.
- The VOC emissions shall not exceed 8.3 pounds per day.
- The VOC emissions during steady state operation shall not exceed 2.0 ppmvd, as methane, @ 15% O_2. Steady-state period refers to any period that is not a start-up or shutdown period.
- The PM10 emissions shall not exceed 79.2 pounds per day.
- The SOx emissions shall not exceed 7.9 pounds per day.
- The ammonia emission concentration shall not exceed 10 ppmvd @ 15% O_2.

VIII. COMPLIANCE (Continued):

C-3929-1-0 (IC engine)

For the emergency IC engine, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- NO_X emissions shall not exceed 5.9 g/hp·hr.
- PM_{10} emissions shall not exceed 0.13 g/hp·hr.

D. Compliance Certification

Section 4.14.3 of this Rule requires the owner of a new major source or a source undergoing a Title I modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed in Sections VIII.C.1.a and VIII.C.1.b, this facility is not a new major source and this project does not constitute a Title I modification, therefore this requirement is not applicable.

E. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment F of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NO_X, CO and SO_X. As shown by the AQIA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO or SO_X.

The proposed location is located in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

VIII. COMPLIANCE (Continued):

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.05	1.96	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

F. Compliance Assurance

1. Source Testing

C-3929-1-0 and C-3929-2-0

District Rule 4703 requires NO_X and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, VOC, CO, PM_{10}, and ammonia slip will be required within 60 days of initial operation and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR part 75.

40 CFR Part 60 subpart GG requires fuel nitrogen content testing. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to fuel nitrogen content testing.

40 CFR Part 60 subpart GG requires that fuel sulfur content be monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

VIII. COMPLIANCE (Continued):

C-3929-3-0

District Rule 4701 requires NO_X, CO and VOC emission testing on a biennial basis (once every 24 months). Since the engine is limited to emergency operation only, it is exempt from the source testing requirements of the rule. Therefore, no source testing will be required for this permit unit.

2. Monitoring

C-3929-1-0 and C-3929-2-0

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

District Rule 4703 requires the facility to monitor the SCR system ammonia injection rate. Ammonia injection rate monitoring will be required.

District Rule 4703 requires the facility to monitor the exhaust temperature and exhaust flow rate. Exhaust temperature and exhaust flow rate monitoring will be required.

District Rule 4703 requires that the elapsed time of operation, on an annual basis be monitored. Such monitoring will be required.

40 CFR Part 60 Subpart GG requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart GG requires monitoring of the fuel nitrogen content. As stated in the Subpart GG compliance section of this document, the District will allow the annual NO_X source test to substitute for this requirement.

40 CFR Part 60 Subpart GG requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas and Electric Company, may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to require only annual fuel sulfur content testing if the SO_X emission factor is based on a fuel sulfur content of 1.0 gr/scf. However, the applicant is proposing a SO_X emission factor based on a fuel sulfur content of 0.25 gr/scf. For such units, fuel sulfur content testing is required more frequently. The facility will be required to test fuel sulfur content weekly until eight consecutive tests show compliance. After that, the

VIII. COMPLIANCE (Continued):

testing frequency may be reduced to quarterly. If a quarterly test fails to show compliance then the testing returns to weekly until eight consecutive weekly tests show compliance. After that, the testing frequency may return to quarterly.

C-3929-3-0

District Rule 4701 requires the monitoring of NO_X and CO emission. As discussed earlier, since the engine is limited to emergency operation only, it is exempt from the monitoring requirements of the rule. Therefore, no monitoring will be required for this permit unit.

3. Recordkeeping

C-3929-1-0 and C-3929-2-0

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

C-3929-3-0

The applicant will be required to keep records of the hours of emergency and non-emergency operation in order to maintain the exemption from the other requirements of District Rule 4701.

4. Reporting

C-3929-1-0 and C-3929-2-0

40 CFR Part 60 Subpart GG requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart GG requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

C-3929-3-0

There are no reporting requirements applicable to this emergency IC engine.

VIII. COMPLIANCE (Continued):

Rule 2520 *Federally Mandated Operating Permits (06/15/95)*

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0. Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA.

Pursuant to Rule 2520 section 5.3.1 GWF Energy must submit a Title V application within 12 months of commencing operations. No action is required at this time.

Rule 2540 *Acid Rain Program (11/13/97)*

The proposed CTGs are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in June of 2002.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

Rule 4001 *New Source Performance Standards, 40 CFR 60 – Subpart GG*

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after 10/03/77. Therefore, this subpart applies to the new turbine installations.

NO_X Requirement §60.332(a):
Under the standard, NO_X emissions from the turbine with a minimum heat input rating of 250 MMBtu/hr are limited by the following equation:

NO_X (% by vol@ 15% O_2) 1 hr avg = 0.0075(14.4/Y)+ F

where: Y = manufacturers rated heat load (kJ/W-hr)
= (10,317 Btu/kW-hr)(kW/1,000 W)(1,054.2 J/Btu)(kJ/1,000 J)[9]
= 10.88 kJ/W-hr (less than 14.4 kJ/W hour)

[9] The rated heat load for the GE LM6000 is 10,317 Btu/kW-hr, per GWF Energy, LLC.

VIII. COMPLIANCE (Continued):

F = 0 (fuel bound nitrogen for natural gas fuel)

NO_X (% by vol@ 15% O_2) = 0.0075(14.4/10.88)+ 0
= 0.0099 %
= 99 ppmv @ 15% O2

GWF Energy, LLC is proposing a NO_X concentration limit of 3.6 ppmv @ 15% O_2 (3 hr average) as required by BACT. Therefore, compliance with the NSPS NO_X standard is expected.

SO_X Requirement §60.333(a) and (b):

The applicable SO_X limits specified in section 60.333 are as follows:

SO_X = 0.015% by vol @ 15% O_2
= 150 ppmv @ 15% O_2

or fuel S ≤ 0.8% by weight.

The 150 ppmv @ 15% O_2 limit specified in section 60.333, paragraph (a) is equivalent to 0.769 lb-SO_X/MMBtu as follows:

$$\frac{(150\text{ ppmvd})\times\left(8{,}578\frac{\text{ft}^3}{\text{MMBtu}}\right)\times\left(64\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)\times\left(\frac{20.9}{20.9-15}\right)}{\left(379.5\frac{\text{ft}^3}{\text{lb}-\text{mol}}\right)\times\left(10^6\right)} = 0.769\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SO_X emissions are based on combusting natural gas with a fuel sulfur content of 0.25 gr/100 scf, which results in an emission rate of 0.00071 lb-SO_X/MMBtu. The percent sulfur by weight of natural gas of 0.25 gr-S/100 scf natural gas is 0.000842, determined as follows (assuming a 100 scf sample comprised of methane at 60 °F):

$$\left(\frac{0.25\text{ gr}-\text{S}}{100\text{ ft}^3-\text{NG}}\right)\times\left(\frac{\text{lb}-\text{S}}{7000\text{ gr}-\text{S}}\right)\times\left(\frac{\text{ft}^3-\text{NG}}{0.0424\text{ lb}-\text{NG}}\right) = 8.42\times10^{-6}\frac{\text{lb}-\text{S}}{\text{lb}-\text{NG}}$$

Both SO_X emissions and fuel sulfur content are less than that required by Subpart GG. Recordkeeping and reporting of the fuel sulfur content is required as specified in section 60.334 (b)(2). Reporting will be performed using an alternative custom reporting schedule.

Reporting and notifications, and initial compliance testing will be required as specified in 40 CFR, Subpart A. Compliance is expected.

VIII. COMPLIANCE (Continued):

Rule 4101 *Visible Emissions (12/17/92)*

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

C-3929-1-0 and C-3929-2-0

The CTGs including lube oil vents will be limited by permit condition to not have visible emissions, except for three minutes in any hour, greater than 5% opacity as a BACT requirement. This is more restrictive than the 20% opacity limit in Rule 4101, therefore compliance is expected.

C-3929-3-0

Under normal operating conditions, the visible emissions limit is not expected to be exceeded for the emergency IC engine, based on similar operations. Therefore, compliance is expected.

Rule 4102 *Nuisance (12/17/92)*

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, compliance with this rule is expected.

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the new gas turbine engines and the emergency IC engine results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy TOX 1, TBACT is not required for any proposed emissions unit as shown in the table below:

VIII. COMPLIANCE (Continued):

SCREEN HRA SUMMARY				
	Natural Gas Turbine #1	Natural Gas Turbine #2	Emergency Diesel IC Engine	Project Total
Acute Hazard Index	0.02	0.02	N/A	0.04
Chronic Hazard Index	0.0	0.0	N/A	0.00
70 yr Cancer Risk	0.0	0.0	0.1	0.1
T-BACT Required?	No	No	No	

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Proposed Rule 4102 Conditions:

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
- During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (C-3929-1 and C-3929-2) shall not exceed the following: NO_x – 15.4 lb, CO – 15.4 lb, and VOC – 1.4 lb in any one hour. [California Environmental Quality Act]

Rule 4201 *Particulate Matter Concentration (12/17/92)*

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

$$\text{PM Conc. (gr/scf)} = \frac{\text{(PM emission rate)} \times \text{(7000 gr/lb)}}{\text{(Air flow rate)} \times \text{(60min/hr)}}$$

C-3929-1-0 and C-3929-2-0

PM_{10} emission rate = 3.3 lb/hr. Assuming 100% of PM is PM_{10}

PM Conc. (gr/scf)=[(3.3 lb/hr) $*$ (7,000 gr/lb)] ÷ [(135,000 ft^3/min) $*$ (60 min/hr)]
PM Conc. = 0.0029 gr/scf

VIII. COMPLIANCE (Continued):

C-3929-3-0

$$0.13\ \frac{g}{hp\cdot hr} \times \frac{1\ hp\cdot hr}{2{,}542.5\ Btu} \times \frac{10^6\ Btu}{9{,}190\ dscf} \times \frac{0.35\ Btu_{out}}{1\ Btu_{in}} \times \frac{15.43\ grain}{g} = 0.03\ gr/dscf$$

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all three permit units will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

Rule 4202 *Particulate Matter Emission Rate (12/17/92)*

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the proposed units.

Rule 4701 *Stationary Internal Combustion Engines (10/16/97)*

Pursuant to Section 4.2.1, emergency IC engines that do not operate more than 200 hours per year for non-emergency use are exempt from the requirements of this rule except for the recordkeeping requirements. The following condition will be included on the permit to satisfy the recordkeeping requirement of the Rule.

- The permittee shall maintain records of hours of emergency and non-emergency operation. Records shall include the date, the number of hours of operation, the purpose of the operation (e.g., load testing, weekly testing, rolling blackout, general area power outage, etc.), and the sulfur content of the diesel fuel used. Such records shall be retained on site for a period of at least two years and made available for District inspection upon request. [District Rule 4701]

Therefore, compliance with Rule 4701 is expected.

Rule 4703 *Stationary Gas Turbines (10/16/97)*

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 46.9 MW gas turbines, therefore this rule applies.

Section 5.1.1 of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR), based on the following equation:

VIII. COMPLIANCE (Continued):

$$NO_X \text{ (ppmv @ 15\% } O_2) = 9 \times \left(\frac{EFF}{25}\right)$$

Where EFF is the higher of EFF_1 or EFF_2 where:

$$EFF_1 = \frac{3{,}412 \frac{Btu}{kW-hr}}{\text{Actual Heat Rate @ HHV } (\frac{Btu}{kW-hr})} \times 100, \text{ and } EFF_2 = EFF_{MFR} \frac{LHV}{HHV}$$

EFF_2 = EFF_{mfr} * (LHV/HHV)

Manufacturer's data indicates that the Actual Heat Rate @ HHV is 10,317 Btu/KW-hr. Therefore:

$$EFF_1 = \frac{3{,}412 \frac{Btu}{kW-hr}}{10{,}317 \frac{Btu}{kW-hr}} \times 100 = 33.07\%$$

$$NO_X \text{ limit utilizing } EFF_1 = 9 \times \left(\frac{33.07}{25}\right) = 11.9 \text{ ppmvd @ 15\% } O_2$$

EFF_2 calculations are not necessary since Rule 4703 emission limits will be no lower than 9 ppmv NO_X and the proposed turbines will be limited to a maximum of 3.6 ppmv NO_X @ 15% O_2 (based on a 3-hour average), therefore compliance is expected.

Section 5.2 limits the CO emissions from stationary gas turbine systems subject to Section 5.1.1 to 200 ppmv CO @ 15% O_2. The proposed turbines will be limited to a maximum of 6 ppmv CO @ 15% O_2, therefore compliance is expected.

Monitoring and recordkeeping:

Sections 6.2 and 6.3 contain the following monitoring, recordkeeping and source testing requirements. These requirements will be included as permit conditions.

- 6.2.1.1 Monitor control system operating parameters. Such as ammonia and exhaust gas flow rates and exhaust gas temperature for selective catalytic reduction (SCR), and humidity, water injection rate, exhaust gas flow rate and temperature for water injection.
- 6.2.1.2 Install, operate, and maintain equipment that continuously measures elapsed time of operation.

VIII. COMPLIANCE (Continued):

- 6.2.1.3 Turbines rated at over 10 MW that operated an average of over 4,000 hours during the past three years are required to install, operate, and maintain in calibration a continuous emissions monitoring system for NO_X. The applicant is proposing a CEMS for NO_X.
- 6.2.2 Maintain records for inspection at any time for a period of two years.
- 6.2.3 Correlate control system operating parameters with NO_X emissions. This requirement applies to the selective catalytic reduction and water injection systems. This information may be used by the APCO to determine compliance when the continuous emissions monitoring system not operating properly.
- 6.2.4 Maintain an operating log that includes, on a daily basis, the actual local start-up and stop time, length and reason for reduced load periods, total hours of operation, type and quantity of fuel used (liquid/gas).
- 6.3 Provide source test information annually regarding the exhaust gas NO_X and CO concentrations.

The facility must demonstrate compliance annually with the NO_X and CO emission limits and determine the demonstrated percent efficiency (EFF) of the stationary gas turbines, using the following test methods:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.
- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

Demonstrated percent efficiency of the stationary gas turbines shall be determined using the facility instrumentation for gas turbine fuel consumption and power output. Power output values used to determine gas turbine efficiency shall be the electrical power output of the gas turbines. Compliance is expected.

Rule 4801 *Sulfur Compounds (12/17/92)*

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

VIII. COMPLIANCE (Continued):

C-3929-1-0 and C-3929-2-0

The sulfur of the natural gas fuel is 0.25 gr/100 dscf.

The ratio of the volume of the SO_X exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_X: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_X produced per MMBtu of fuel.
- Weight of SO_X as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00071\,lb}{MMBtu} \times \frac{1\,(lb-mol)}{64\,lb} = 0.000011\,(lb-mol)$
- $R = \frac{0.7302\,ft^3 \cdot atm}{(lb-mol)\,°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000011\,(lb-mol) \cdot \frac{0.7302\,ft^3 \cdot atm}{(lb-mol)\,°R} \cdot 500\,°R}{1\,atm}$$

$$V = 0.004\,ft^3$$

Since the total volume of exhaust per MMBtu is 8,710 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.004}{8{,}710} = 0.00000046 = 0.46\,ppmv = 0.000046\%\ by\ volume$$

46 ppmv ≤ 2000 ppmv, therefore the gas turbine engines are expected to comply with Rule 4801.

VIII. COMPLIANCE (Continued):

C-3929-3-0

The sulfur content of the diesel fuel is 0.05% sulfur by weight.

$$0.05\%\ S \times \frac{7.1\ lb}{gal} \times \frac{64\ lb \cdot SO_2}{32\ lb \cdot S} \times \frac{1\ MMBtu}{9{,}190\ scf} \times \frac{1\ gal}{0.137\ MMBtu} \times \frac{lb \cdot mol}{64\ lb \cdot SO_2} \times \frac{10.73\ psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520\ {}^\circ R}{14.7\ psi} = 33.4\ ppmv$$

Since 33.4 ppmv is ≤ 2000 ppmv, this engine is expected to comply with Rule 4801.

Rule 8010 *Fugitive Dust Administrative Requirements for Control of PM10 (04/25/96)*

The purpose of this Rule is to set forth the definitions, exemptions, requirements, administrative requirements, and fees applicable to all Rules in Regulation VIII.

Rule 8020 *Fugitive Dust Requirements for Control of PM10 From Construction, Demolition, Excavation, and Extraction Activities (04/25/96)*

The purpose of this Rule is to limit fugitive dust emissions from construction, demolition, excavation, and related activities. It requires the use of reasonably available control measures (RACM), as defined in Rule 8010, to maintain visible dust emissions (VDE) under the 40% opacity requirement.

The Henrietta Peaker Project will commit to implementing RACM via the use of dust control measures (e.g., water, approved chemical stabilizers, etc.) during construction to maintain opacity to a level below 40% per Rule 8020 requirements.

California Environmental Quality Act (CEQA)

The California Energy Commission (CEC) is the lead Agency for CEQA. Generally, the District cannot make its final decision on ATCs until CEQA has been satisfied. For power generating projects that qualify for expedited processing (per District policy), the ATCs will be issued if the District's analysis and public notice is completed prior to CEQA approval. If the ATCs are issued prior to CEQA approval, the ATCs will include the following condition:

- The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

VIII. COMPLIANCE (Continued):

California Health & Safety Code, Section 42301.6 School Notice

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 Air Toxic "Hot Spots"

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.
2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.
3. The district issues a permit authorizing construction or operation of the new facility

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than one in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Preliminary Determination of Compliance for the facility subject to the proposed conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-3929-1-0	3020-8B-A	46,900 kW	$8,757.00
C-3929-2-0	3020-8B-A	46,900 kW	$8,757.00
C-3929-3-0	3020-10-C	397 hp	$205.00

ATTACHMENT A

PROPOSED CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3929-1-0:
46.9 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 PC SPRINT NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEM, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST.

- The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act] N

- Upon implementation of C-3929-1-0 and C-3929-2-0, emission offsets shall be provided to offset emissions increases in the following amounts: PM10 - Q1: 8,850 lb, Q2: 8,850 lb, Q3: 8,850 lb, and Q4: 8,850 lb and NOx (as NO2) - Q1: 29,055 lb, Q2: 30,210 lb, Q3: 30, 210 lb, and Q4: 29,055 lb. Offsets shall be provided at the appropriate offset ratio specified in Rule 2201 Section 4.2.4. SOx offsets provided to offset PM10 increases shall be at a ratio of 1.4:1 at the appropriate distance ratio. [District Rule 2201] N

- The permittee shall notify the District of the date of initiation of construction no later than 30 days after such date, the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date. [District Rule 4001] N

- Selective catalytic reduction (SCR) system and oxidation catalyst shall serve the gas turbine engine. Exhaust ducting shall be equipped with a fresh air inlet and blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. Permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201] N

- Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201] N

- The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703] N

- {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District NSR Rule] N

- {118} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102] N

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] N

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] N

- Combustion turbine generator (CTG) and generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rule 2201] N

- The CTG shall be equipped with a continuous monitoring system to measure and record hours of operation and fuel consumption. [District Rules 2201, 4001, and 4703] N

- Operation of the turbine shall not exceed 8,000 hours per calendar year. [District Rule 2201] N

- The CTG shall be equipped with a continuous emission monitor (CEM) for NOx (before and after SCR system), CO, and O2. Continuous emissions monitor(s) shall meet the requirements of 40 CFR part 60, Appendices B and F, and 40 CFR part 75, and District-approved protocol, and shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEM(s) pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 2201, 4001, and 4703] N

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081] N

- The CTG shall be fired exclusively on natural gas with a sulfur content of no greater than 0.25 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201] N

- During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (C-3929-1 and C-3929-2) shall not exceed the following: NOx (as NO2) - 15.4 lb, CO - 15.4 lb, and VOC - 1.4 lb in any one hour. [California Environmental Quality Act] N

- Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in condition #19. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown of gas turbine engine shall not exceed a time period of one hour each per occurrence. Startup and shutdown events shall not exceed 250 occurrences per calendar year and once per day. [District Rule 2201] N

- Emission rates from this unit, except during startup and shutdown events, shall not exceed any of the following: NOx (as NO2) - 5.9 lb/hr and 3.6 ppmvd @ 15% O2; VOC (as methane) - 0.33 lb/hr and 2.0 ppmvd @ 15% O2; CO - 2.44 lb/hr and 6.0 ppmvd @ 15% O2; PM10 - 3.3 lb/hr; or SOx (as SO2) - 0.33 lb/hr. All emission concentration limits are three-hour rolling averages. [District Rules 2201, 4001, and 4703] N

- Maximum daily emissions from this unit shall not exceed any of the following: NOx (as NO2) - 143.4 lb/day; VOC - 8.3 lb/day; CO - 63.8 lb/day; PM10 - 79.2 lb/day; and SOx (as SO2) - 7.9 lb/day. [District Rule 2201] N

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201] N

- Compliance with ammonia slip limit shall be demonstrated utilizing the following calculation procedure: ammonia slip ppmvd @ 15% O2 = ((a - (b x c/1,000,000)) x (1,000,000 / b) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee shall submit a monitoring plan for District review and approval. [District Rule 4102] N

- Source testing to measure the NOx, CO, and VOC emission limits (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days of initial operation of the CTG and at least once every twelve months thereafter. [District Rule 1081] N

- Source testing to measure the PM10 emission limit (lb/hr), the natural gas sulfur content limit, and the ammonia emission limit shall be conducted within 60 days of initial operation and at least once every twelve months thereafter. [District Rule 1081] N

- Source testing of startup NOx, CO, VOC, and PM10 mass emission rates shall be conducted for one of the gas turbine engines (C-3929-1 or C-3929-2) upon initial operation and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081] N

- Source testing to determine the percent efficiency of the turbine shall be within 60 days of initial operation and at least once every twelve months thereafter. [District Rule 4703] N

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] N

- The following test methods shall be used PM10: EPA Method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA Method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA Method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703] N

- Source testing to determine the percent efficiency of the turbine shall be conducted utilizing the procedures in District Rule 4703 (Stationary Gas Turbines). [District Rule 4703] N

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703] N

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703] N

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080] N

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] N

- The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] N

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100] N

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100] N

- The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080] N

- All records required to be maintained by this permit shall be maintained for a period of two years and shall be made readily available for District inspection upon request. [District Rule 2201] N

- Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520] N

- Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program. [District Rule 2540] N

EQUIPMENT DESCRIPTION, UNIT C-3929-2-0:
46.9 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 PC SPRINT NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEM, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST.

- The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act] N

- Upon implementation of C-3929-1-0 and C-3929-2-0, emission offsets shall be provided to offset emissions increases in the following amounts: PM10 - Q1: 8,850 lb, Q2: 8,850 lb, Q3: 8,850 lb, and Q4: 8,850 lb and NOx (as NO2) - Q1: 29,055 lb, Q2: 30,210 lb, Q3: 30, 210 lb, and Q4: 29,055 lb. Offsets shall be provided at the appropriate offset ratio specified in Rule 2201 Section 4.2.4. SOx offsets provided to offset PM10 increases shall be at a ratio of 1.4:1 at the appropriate distance ratio. [District Rule 2201] N

- The permittee shall notify the District of the date of initiation of construction no later than 30 days after such date, the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date. [District Rule 4001] N

- Selective catalytic reduction (SCR) system and oxidation catalyst shall serve the gas turbine engine. Exhaust ducting shall be equipped with a fresh air inlet and blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. Permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201] N

- Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201] N

- The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703] N

- {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District NSR Rule] N

- {118} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102] N

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] N

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] N

- Combustion turbine generator (CTG) and generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rule 2201] N

- The CTG shall be equipped with a continuous monitoring system to measure and record hours of operation and fuel consumption. [District Rules 2201, 4001, and 4703] N

- Operation of the turbine shall not exceed 8,000 hours per calendar year. [District Rule 2201] N

- The CTG shall be equipped with a continuous emission monitor (CEM) for NOx (before and after SCR system), CO, and O2. Continuous emissions monitor(s) shall meet the requirements of 40 CFR part 60, Appendices B and F, and 40 CFR part 75, and District-approved protocol, and shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEM(s) pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 2201, 4001, and 4703] N

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081] N

- The CTG shall be fired exclusively on natural gas with a sulfur content of no greater than 0.25 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201] N

- During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (C-3929-1 and C-3929-2) shall not exceed the following: NOx (as NO2) - 15.4 lb, CO - 15.4 lb, and VOC - 1.4 lb in any one hour. [California Environmental Quality Act] N

- Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in condition #19. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown of gas turbine engine shall not exceed a time period of one hour each per occurrence. Startup and shutdown events shall not exceed 250 occurrences per calendar year and once per day. [District Rule 2201] N

- Emission rates from this unit, except during startup and shutdown events, shall not exceed any of the following: NOx (as NO2) - 5.9 lb/hr and 3.6 ppmvd @ 15% O2; VOC (as methane) - 0.33 lb/hr and 2.0 ppmvd @ 15% O2; CO - 2.44 lb/hr and 6.0 ppmvd @ 15% O2; PM10 - 3.3 lb/hr; or SOx (as SO2) - 0.33 lb/hr. All emission concentration limits are three-hour rolling averages. [District Rules 2201, 4001, and 4703] N

- Maximum daily emissions from this unit shall not exceed any of the following: NOx (as NO2) - 143.4 lb/day; VOC - 8.3 lb/day; CO - 63.8 lb/day; PM10 - 79.2 lb/day; and SOx (as SO2) - 7.9 lb/day. [District Rule 2201] N

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201] N

- Compliance with ammonia slip limit shall be demonstrated utilizing the following calculation procedure: ammonia slip ppmvd @ 15% O2 = ((a - (b x c/1,000,000)) x (1,000,000 / b) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee shall submit a monitoring plan for District review and approval. [District Rule 4102] N

- Source testing to measure the NOx, CO, and VOC emission limits (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days of initial operation of the CTG and at least once every twelve months thereafter. [District Rule 1081] N

- Source testing to measure the PM10 emission limit (lb/hr), the natural gas sulfur content limit, and the ammonia emission limit shall be conducted within 60 days of initial operation and at least once every twelve months thereafter. [District Rule 1081] N

- Source testing of startup NOx, CO, VOC, and PM10 mass emission rates shall be conducted for one of the gas turbine engines (C-3929-1 or C-3929-2) upon initial operation and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081] N

- Source testing to determine the percent efficiency of the turbine shall be within 60 days of initial operation and at least once every twelve months thereafter. [District Rule 4703] N

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] N

- The following test methods shall be used PM10: EPA Method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA Method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA Method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703] N

- Source testing to determine the percent efficiency of the turbine shall be conducted utilizing the procedures in District Rule 4703 (Stationary Gas Turbines). [District Rule 4703] N

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703] N

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703] N

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080] N

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] N

- The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] N

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100] N

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100] N

- The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080] N

- All records required to be maintained by this permit shall be maintained for a period of two years and shall be made readily available for District inspection upon request. [District Rule 2201] N

- Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520] N

- Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program. [District Rule 2540] N

EQUIPMENT DESCRIPTION, UNIT C-3929-2-0:
382 HP CATERPILLAR MODEL 3306 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 250 KW GENERATOR.

- {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District NSR Rule] N

- {118} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102] N

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] N

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] N

- {311} The engine shall be equipped with a positive crankcase ventilation (PCV) system or a crankcase emissions control device of at least 90% control efficiency. [District NSR Rule] N

- The exhaust stack shall not be fitted with a rain cap, or any other similar device, that impedes vertical exhaust flow. [District Rule 4102] N

- NOx emissions shall not exceed 5.09 g/hp-hr. [District Rule 2201] N

- PM10 emissions shall not exceed 0.13 g/hp-hr. [District Rule 4102] N

- {1344} The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District NSR Rule and District Rule 4701] N

- {313} The sulfur content of the diesel fuel used shall not exceed 0.05% by weight. [District NSR Rule] N

- The permittee shall maintain records of hours of emergency and non-emergency operation. Records shall include the date, the number of hours of operation, the purpose of the operation (e.g., load testing, weekly testing, rolling blackout, general area power outage, etc.), and the sulfur content of the diesel fuel used. Such records shall be retained on-site for a period of two years and made available for District inspection upon request. [District Rule 1070] N

ATTACHMENT B

CTG Emissions Data

Table 8.1-14
Criteria Pollutant Emission Rates for the Turbine with SCR and Oxidation Catalyst During Normal Operation (pounds per hour)

CTG Load	Pollutant	Ambient Temperature 15 °F	63 °F	115 °F
100%	VOC	1.17	0.33	0.20
	CO	6.25	2.44	0.80
	NO_x	6.21	5.90	5.30
	SO_2	0.32	0.30	0.27
	PM_{10}	3.3	3.3	3.2
60%	VOC	0.72	0.15	0.14
	CO	4.02	1.64	0.59
	NO_x	4.28	4.10	3.78
	SO_2	0.22	0.21	0.19
	PM_{10}	3.2	3.2	3.2

Table 8.1-15
Criteria Pollutant Emission Rates for the HPP Turbine During Startup and Shutdown

Pollutant	Startup & Shutdown (Total lb/hr)[a]
NO_x	7.7
CO	7.7
SO_2	0.33
PM_{10}	3.14

[a] Total emissions (per turbine) during an hour assuming both a startup and shutdown averaged into the hourly period.

ATTACHMENT C

SJVAPCD BACT GUIDELINE 3.4.8 & 3.1.2

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.8*

Last Update: June 14, 2001

Emission Unit: Gas Fired Turbine - < 50 MW, Uniform Load, Without Heat Recovery, Serving an Electrical Generator

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	6.25 ppmv @15% O2 (PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with ≤ 0.75 grams S/100 dscf).	1. 90% control efficiency (SCONOx system, or equal). 2. 70 % control efficiency (Oxidation catalyst or equal).	
NOx	5 ppmv @ 15% O2 (Selective Catalytic Oxidation (SCR), or equal).	1. 2.5 ppmv @ 15% O2 (SCONOx system, or equal). 2. 3.0 ppmv (Dry Low-NOx combustors and SCR, or equal)	
PM10	Air inlet cooler/filter, lube oil vent coalescer (or equal) and either PUC-regulated natural gas, LPG, or non-PUC-regulated gas with ≤ 0.75 grams S/100 dscf.		
SOx	PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with ≤ 0.75 grams S/100 dscf.		
CO	6.0 ppmvd @ 15% O2 (Oxidation catalyst and either PUC-regulated natural gas, LPG, or non-PUC-regulated gas with ≤ 0.75 grams S/100 dscf, or equal).	90% control efficiency (SCONOx system, or equal).	

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.8A

Emission Unit: Natural gas fired , Pratt & Whitney Model FT-8 Twin-PAC turbine powering an electrical generator.

Equipment Rating: 49.3 MW

Facility: CalPeak Power LC

References: ATC #: C-3811-1-0
Project #: C-1010207

Location: Mendota, CA

Date of Determination: May 12, 2001

Pollutant	BACT Requirements
NO_x	3.0 ppmvd @ 15% O2, 3-hour average (Dry Low-NOx combustors and SCR with PUC-regulated natural gas).
VOC	2.0 ppmv @ 15% O2 (Oxidation Catalyst)
PM_{10}	0.0066 lb/MMBtu (PUC-regulated natural gas, air inlet cooler/filter and lube oil coalescer).
SO_x	PUC-regulated fuel.
CO	BACT NOT TRIGGERED

BACT Status:

X Achieved in practice (SOx, VOC & PM10)

___ Small Emitter

___ T-BACT

X Technologically feasible BACT (NOx)

___ At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT

___ Contained in EPA approved SIP

X The following technologically feasible options were not cost effective:

___ Alternate Basic Equipment

___ The following alternate basic equipment was not cost effective:

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.8B

Emission Unit: Natural gas fired , GE LM6000 turbine powering an electrical generator.

Equipment Rating: 47.5 MW

References: ATC #: C-603-11-0
Project #: C-1010451

Facility: Hanford LP

Location: Hanford, CA

Date of Determination: June 14, 2001

Pollutant	BACT Requirements
NO_x	3.4 ppmvd @ 15% O2, 3-hour average (Water-spray pre-mixed combustion system and SCR with PUC-regulated natural gas).
VOC	2.0 ppmv @ 15% O2 (Oxidation Catalyst)
PM_{10}	0.0066 lb/MMBtu (PUC-regulated natural gas, air inlet cooler/filter and lube oil coalescer).
SO_x	PUC-regulated fuel.
CO	6.0 ppmvd @ 15% O2 (Oxidation catalyst and PUC-regulated natural gas).

BACT Status: X Achieved in practice (CO) ___ Small Emitter ___ T-BACT

___ Technologically feasible BACT

___ At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT

___ Contained in EPA approved SIP

X The following technologically feasible options were not cost effective:
1) SCONOx - CO

___ Alternate Basic Equipment

___ The following alternate basic equipment was not cost effective:

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.2*

Last Update: June 30, 2001

Emission Unit: Emergency Diesel I.C. Engine - ≥ 175 hp and < 400 hp

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Positive crankcase ventilation		
SO_x	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
NO_x	Certified NO_x emissions of 6.9 g/bhp-hr or less.		
PM_{10}	0.1 grams/bhp-hr (if TBACT is triggered) 0.4 grams/bhp-hr (if TBACT is not triggered)		

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.2A

Emission Unit: Diesel I.C. Engine Driving Emergency Generator

Equipment Rating: $\geq$ 117 hp and < 400 hp

Facility: N/A

References: ATC #: SCAQMD BACT
Project #:

Location: N/A

Date of Determination: July 27, 1995

Pollutant	BACT Requirements
NO_x	Certified NO_x emissions of 10.0 g/bhp-hr
VOC	Positive crankcase ventilation
PM_{10}	Low-sulfur diesel fuel (0.05% by weight sulfur or less) and positive crankcase ventilation or crankcase control device
SO_x	Low-sulfur diesel fuel (0.05% by weight sulfur or less)
CO	BACT NOT TRIGGERED

BACT Status: X Achieved in practice — Small Emitter — T-BACT

— Technologically feasible BACT

— At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT

— Contained in EPA approved SIP

— The following technologically feasible options were not cost effective:

— Alternate Basic Equipment

— The following alternate basic equipment was not cost effective:

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.2B

Emission Unit: Diesel I.C. Engine Driving Emergency Generator

Equipment Rating: $\geq$ 175 hp and < 400 hp

References: SJVUAPCD TBACT based on ARB Determination for PM Control measures and EPA NOx emission standards

Facility: N/A

Location: N/A

Date of Determination: March 5, 2001

Pollutant	BACT Requirements
NO_x	6.9 gram/bhp-hr
VOC	BACT NOT TRIGGERED
PM_{10}	0.1 grams/bhp-hr (if TBACT is triggered) 0.4 grams/bhp-hr (if TBACT is not triggered)
SO_x	Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available
CO	BACT NOT TRIGGERED

BACT Status: X Achieved in practice — Small Emitter X T-BACT

— Technologically feasible BACT

— At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT

— Contained in EPA approved SIP

— The following technologically feasible options were not cost effective:

— Alternate Basic Equipment

— The following alternate basic equipment was not cost effective:

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.2C

Emission Unit: Diesel I.C. Engine Driving Emergency Generator

Equipment Rating: $\geq$ 175 hp and < 400 hp

Facility: N/A

References: EPA compression ignition engine performance standard 40 CFR Part 89.

Location: N/A

Date of Determination: June 30, 2001

Pollutant	BACT Requirements
NO_x	6.9 gram/bhp-hr
VOC	BACT NOT TRIGGERED
PM_{10}	BACT NOT TRIGGERED
SO_x	BACT NOT TRIGGERED
CO	BACT NOT TRIGGERED

BACT Status: X Achieved in practice — Small Emitter — T-BACT

__ Technologically feasible BACT

__ At the time of this determination achieved in practice BACT was equivalent to technologically feasible BACT

__ Contained in EPA approved SIP

__ The following technologically feasible options were not cost effective:

__ Alternate Basic Equipment

__ The following alternate basic equipment was not cost effective:

ATTACHMENT D

TOP DOWN BACT ANALYSIS (C-3929-1-0 & C-3929-2-0)

1. BACT Applicability:

Pursuant to Sections 4.1.1 and 4.1.2, BACT shall be applied to a new, relocated, or modified emissions unit if the new or relocated unit has a Potential to Emit (PE) exceeding two pounds in any one day or the modified emissions unit results in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2 lb/day for NO_X, CO, VOC, PM_{10}, or SO_X. For CO emissions, the CO Post-project Stationary Source Potential to Emit (SSPE2) must also exceed 200,000 lb/year to trigger BACT.

As seen in Section VII.D of this evaluation, the applicant is proposing to install new emissions units with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day, but BACT is not triggered for CO emissions since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.E.2 of this document.

2. BACT Guidance:

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. The District BACT Clearinghouse recently included a new BACT Guideline (3.4.8) applicable to the turbine installations [Simple Cycle Gas Fired Turbines less than 50 MW, Powering an Electrical Generation Operation]. (See Attachment C)

3. Top-Down BACT Analysis:

A. NO_X Top-Down BACT Analysis for Permits (C-3929-1-0 & -2-0)

According to BACT guideline 3.4.8 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for NO_X emissions from similar operations.

Step 1 - <u>Identify All Possible Control Technologies</u>

Based on the previously cited BACT Guideline, general control for NO_X emissions from turbines include the following options:

1. Selective Catalytic Reduction (SCR) systems: consist of injecting ammonia upstream of a catalyst bed. The ideal operating temperature for a conventional SCR catalyst is 600 – 750 °F (titanium oxide). High temperature zeolite SCR catalysts have been developed that permit continuous SCR operation at temperatures as high as 1,050 °F. High temperature catalysts must be used when the SCR system needs to be placed upstream of the Heat Recovery Steam Generators (HRSG) or on a simple cycle turbine without heat recovery.

3. Top-Down BACT Analysis (Continued):

2. SCONO$_X$™: employs a precious metal catalyst and a NO$_X$ absorption/regeneration process step to convert CO and NO$_X$ into CO_2, H_2O, and N_2. The principle advantage of the SCONO$_X$™ technology over SCR is the elimination of ammonia emissions and the simultaneous reduction of CO, VOC, and NO$_X$. SCONO$_X$™ has a maximum operating temperature of ≈ 700 °F

3. Catalytic Combustors (Xonon™ technologies): are flameless processes that allow fuel oxidation to take place at temperatures well below the normal lean flammability limits of the air-fuel mixture. For this reason, the use of catalysts in gas turbine combustion to replace part of the thermal reaction zone allows stable combustion to occur at peak temperatures that are as much as 1,800 °F lower than those of conventional combustors.

4. Dry Low NO$_X$ (DLN) Combustors: operate in a pre-mixed mode, where air and fuel are mixed before entering the combustor. An important advantage of the DLN combustor is that the amount of NO$_X$ formed does not increase with an increase in residence time. This means that DLN systems can be designed with long residence times to achieve low CO and low VOC emissions, while maintaining low NO$_X$ levels.

5. Water/Steam Injection: has been used for the past 25 years to control NO$_X$ emissions from gas turbines. Manufacturers typically guarantee water injected combustors to 42 ppmv when firing natural gas. The maximum allowable water injection rate is determined by the CO and VOC limits on the unit (as water injection has a quenching effect that increases emissions of "products of incomplete combustion") and the rapid wear caused by direct water impingement on the combustor liner.

<u>NO$_X$ Emissions Control Technologies</u>

a. SCONO$_X$™
b. Catalytic Combustors (Xonon™ technologies)
c. Selective Catalytic Reduction (SCR) systems
d. Dry Low NO$_X$ (DLN) Combustors
e. Water/Steam Injection

3. Top-Down BACT Analysis (Continued):

Step 2 - Eliminate Technologically Infeasible Options

The Xonon™ catalytic combustors are considered technologically infeasible for this installation because the combustors are not commercially available for any turbine type at this time, according to Chuck Solt, regulatory affairs director of Catalytica Combustion Systems. Only since October of 1998 has this Xonon technology been placed on a turbine installation. Genxon Power Systems installed a 1.55 MW natural gas fired Kawasaki MIA-13A combustion gas turbine to produce electricity for the city of Santa Clara. To date, this has been the only installation that is equipped with the Xonon technology, and the technology has not been applied to larger sized turbine installations. The Xonon system has been performing as designed, providing 2.5 ppmv NO_X emissions from the turbine for over 7,400 hours of operation, but this is the only turbine manufacturer that has had an industry installation. GWF Energy could install Kawasaki turbines at their facility, but to provide the amount of energy needed by the power plant (93.8 MW), they would have to install 60 turbines, instead of the one turbine they have proposed. Since one Kawasaki turbine is not large enough to supply the power output needed by GWF Energy, the District will not require the installation of extra turbines in order to utilize a specific control technology.

All remaining control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. $SCONO_X$™ - $\leq$ 2.5 ppmv
2. Selective Catalytic Reduction - $\leq$ 5[1] ppmv
3. Dry Low NO_X burner - $\leq$ 25[2] ppmv
4. Water Injection - $\leq$ 42 ppmv

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_X reduction is $9,700 per ton of NO_X reduced.

[1] Selective Catalytic Reduction (SCR) systems are capable of achieving emission levels less than 5 ppmv NO_X, but achieving such emissions has not been fully demonstrated on a consistent basis.
[2] It has generally been noted that Turbine manufacturers commonly guarantee NO_X emissions of 25 ppmv @ 15% O_2.

3. Top-Down BACT Analysis (Continued):

The industry standard for turbines of this class and category of source was determined to be 25 ppmv NO_X @ 15% O_2.[3] The proposed annual emissions from a gas turbine using industry standard values can be calculated as:

<u>NO_X (annual):</u>

$$\frac{0.0921\ \text{lb}}{\text{MMBtu}} \left| \frac{3{,}676{,}800\ \text{MMBtu}}{\text{year}} \right. = 338{,}633\ \text{lb}\ NO_X/\text{year}$$

(25 ppmv @ 15% O_2 = 0.0921 lb/MMBtu)

PE_{NOx} = 338,663 lb NO_X/year = 169.3 tons NO_X/year

The proposed annual emissions from a gas turbine equipped the $SCONO_X$ control technology with NO_X emissions of 2.5 ppmv @ 15% O_2 can be calculated as:

<u>NO_X (annual):</u>

$$\frac{0.0092\ \text{lb}}{\text{MMBtu}} \left| \frac{3{,}676{,}800\ \text{MMBtu}}{\text{year}} \right. = 33{,}827\ \text{lb}\ NO_X/\text{year}$$

(2.5 ppmv @ 15% O_2 = 0.0092 lb/MMBtu)

PE_{NOx} = 33,826 lb NO_X/year = 16.9 tons NO_X/year

1. NO_X Cost Effectiveness Analysis:
$SCONO_X$ Systems (by Goal Line Environmental Technologies)

The District conducted research attempting to first, determine whether or not the control technology would be feasible for this type of installation, because the outlet temperature of the turbine exhaust was at approximately 700 °F. Published throughout the company's website, stated that the ideal operating parameters for the $SCONO_X$ system was between 300 °F to 700 °F, and therefore raised the question on whether or not the $SCONO_X$ system would operate properly for this simple cycle installation. On a recent BACT analysis, the District was able to contact a Mr. Greg Gilbert of Goal Line Environmental Technologies (GLET) from the company's Sacramento office and briefly discuss with him the scope of the turbine installation project for a similar simple cycle turbine installation. Based upon that conversation, Mr. Gilbert stated that a facility would be able to install $SCONO_X$ on a simple cycle installation, with the use of exhaust cooling technologies. Therefore, the control technology is feasible for this installation.

[3] Based upon the fact that there are only a few existing turbine installations within this class and category of source that operate with emissions of 5 ppmv NO_X, the District will assume that the Industry Standard will be 25 ppmv NO_X @ 15% O_2, pursuant to a survey of turbine manufacturers stating that the majority of all turbines sold, are equipped with Dry Low NO_X technology and guaranteed emissions of 25 ppmv.

3. Top-Down BACT Analysis (Continued):

The District conducted more research to determine the appropriate cost information regarding the $SCONO_X$ control technology. Based upon a prior quote from a Mr. Richard Davis of Goal Line Environmental Technologies, the installation of a $SCONO_X$ system (including the exhaust cooling devices) for a 50 MW turbine was approximately $4.0 - $4.5 million. The District will assume the lower cost of $4.0 million dollars as the conservative installation cost for a $SCONO_X$ system.

Description of Cost	Cost Factor	Cost	Source
Direct Capital Costs (DC):			
Purchase Equipment Costs (PE):			
(A) Basic Equipment: $SCONO_X$ System		4,000,000	GoalLine
(B) Instrumentation: included in base price		0	OAQPS
Taxes and Freight:	0.08 A*B	320,000	OAQPS
PE Total:		**4,320,000**	
Direct Installation Costs (DI): Assume Modular SCR w/ simple installation			
Foundation and Supports:	0.08 PE	345,600	OAQPS
Handling and Erection:	0.14 PE	604,800	OAQPS
Electrical:	0.04 PE	172,800	OAQPS
Piping:	0.02 PE	86,400	OAQPS
Insulation:	0.01 PE	43,200	OAQPS
Painting:	0.01 PE	43,200	OAQPS
DI Total:		1,301,400	
Site Preparation and Buildings			
DC Total = PE + DI:		5,621,400	
Indirect Costs (IC):			
Engineering:	0.10 PE	432,000	OAQPS
Construction and Field Expenses:	0.05 PE	216,000	OAQPS
Contractor Fees:	0.10 PE	432,000	OAQPS
Start-up:	0.02 PE	86,400	OAQPS
Performance Testing:	0.01 PE	43,200	OAQPS
Contingencies:	0.03 PE	129,600	OAQPS
IC Total:		1,339,200	
Total Capital Investments (TCI = DC + IC):		6,960,600	
Direct Annual Costs (DAC): Assume $SCONO_X$ requires 0.5 hrs/shift			
Operating Costs (O): 3 shifts per 24 hr/day; 8,000 hours/year (≈ 1,000 shifts/year)			
Operator: 0.50 hr/shift	$25/hr	12,500	OAQPS
Supervisor:	15% operator	1,875	OAQPS
Maintenance Costs (M):			
Labor: 0.5 hr/shift	$25/hr	12,500	OAQPS
Material:	100% labor	12,500	OAQPS
Utility Costs (U):			
Performance loss:	0.6%		
Electricity Cost:	$0.08/kWh	180,096	Variable per GoalLine

3. Top-Down BACT Analysis (Continued):

Catalyst Replace:		374,054[4]	GoalLine
Catalyst Washing:	Variable	36,000	GoalLine
Catalyst Dispose: (Precious Metal Recovery = 1/3 replace cost)		-124,685	GoalLine
H_2 carrier stream: 93 lb steam/hr/MW (@ \$0.008/lb)	Variable	279,149	GoalLine
H_2 reforming: 14 ft^3 CH_4/hr/MW (@ \$0.004/ft^3)	Variable	21,011	GoalLine
Total DAC:		805,000	
Indirect Annual Costs (IAC):			
Overhead:	60% O & M	23,625	OAQPS
Administrative:	0.02 TCI	139,212	OAQPS
Insurance:	0.01 TCI	69,606	OAQPS
Property Tax:	0.01 TCI	69,606	OAQPS
Annualized Total Capital Investment: interest rate (%) 10 Period (years): 10	0.1627 TCI	1,132,490	District Policy
Total IAC:		1,434,539	
Total Annual Cost (DAC + IAC):		**2,239,539**	

District BACT policy requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a $SCONO_X$ system will control NO_X, CO, and VOC emissions, but since BACT is not triggered for CO emissions, CO emissions reductions need not be included in the threshold. The MCET is calculated as follows:

$$MCET (\$/yr) = (E_{NOx} * T_{NOx}) + (E_{VOC} * T_{VOC})$$

Where: E_{NOx} = tons-NO_X controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_X
= \$9,700/ton-NO_X
T_{VOC} = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

To determine E_{VOC}, the District has to establish what Industry Standard is for VOC emissions. As detailed above, turbines with NO_X emissions of 25 ppmv (as determined from a survey of various turbine manufacturers) were deemed as the industry standard for this class and category of source. These turbines were commonly equipped with Dry Low NO_X (DLN) combustor technology to achieve NO_X emission levels of 25 ppmv. Most turbine manufacturers that sold turbines equipped with DLN technology also guaranteed UHC (Total Hydrocarbons) emissions of 25 ppmv. Available AP-42 and ARB data indicate that Non-Methane Hydrocarbons (NMHC) are approximately 25% of total hydrocarbons. ($\Rightarrow$ 25 ppmv $*$ 0.25 = 6.25 ppmv VOC). Therefore, since there were no VOC limitations required by District Rule 4703, the District will consider the Industry Standard for this class and category of source to be 6.25 ppmv VOC @ 15%O_2.

[4] See Appendix I

3. Top-Down BACT Analysis (Continued):

Therefore, the proposed VOC emissions from the gas turbine using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.008 \text{ lb}}{\text{MMBtu}} \cdot \frac{3{,}676{,}800 \text{ MMBtu}}{\text{year}} = 29{,}414 \text{ lb VOC/year}$$

(6.25 ppmv @ 15% O_2 = 0.008 lb/MMBtu)

PE_{VOC} = *29,414 lb VOC/year = 14.7 tons VOC/year*

The District will assume a 90% VOC control efficiency for the installation of a $SCONO_X$ system.[5] The industry standard turbine VOC emissions using a $SCONO_X$ system is:

VOC (annual):

$$\frac{29{,}414 \text{ lb VOC}}{\text{year}} \cdot \frac{(1-90\%)}{1} = 2{,}941 \text{ lb VOC/year}$$

PE_{VOC} = *2,941 lb VOC/year = 1.5 tons VOC/year*

Calculating for the MCET derives the following:

E_{NOx} = 169.3 tpy – 16.9 tpy = 152.4 tpy
E_{VOC} = 14.7 tpy – 1.5 tpy = 13.2 tpy

MCET ($/yr) = (152.4 * $9,700) + (13.2 * $5,000) = $1,554,280/year

The cost of utilizing a $SCONO_X$ system ($2,239,539/year) is more than the MCET of $1,5442,280/year. Therefore, this control technology will be removed from consideration.

2. NO_X Cost Effectiveness Analysis: Turbine equipped with SCR System (5 ppmv NO_X @ 15% O_2)

The applicant is proposing to utilize water injection and a Selective Catalytic Reduction system with NO_X emissions of less than 5 ppmv @ 15% O_2. Since this control technology is the most effective NO_X control technology listed in Step 3, a cost effectiveness analysis is not required.

[5] Per Richard Davis, GLET Representative, the control efficiencies for CO and VOC emissions are "greater than 90%." The District will assume a 90% control efficiency to remain conservative.

3. Top-Down BACT Analysis (Continued):

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of water injection and a Selective Catalytic Reduction system with emissions of less than or equal to 5 ppmv @ 15% O_2. The facility has proposed to use water injection and a Selective Catalytic Reduction system with emissions of less than or equal to 3.6 ppmv @ 15% O_2; therefore, BACT is satisfied.

B. VOC Top-Down BACT Analysis for Permits (C-3929-1-0 & -2-0)

According to BACT guideline 3.4.8 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for VOC emissions from similar operations.

Step 1 - Identify All Possible Control Technologies

General control for VOC emissions include the following options:

1. $SCONO_X$™: employs a precious metal catalyst and a NO_X absorption/regeneration process step to convert CO and NO_X into CO_2, H_2O, and N_2. The principle advantage of the $SCONO_X$™ technology over SCR is the elimination of ammonia emissions and the simultaneous reduction of CO, VOC, and NO_X. $SCONO_X$™ has a maximum operating temperature of ≈ 700 °F

2. Oxidation Catalysts: utilizes the use of a catalyst bed (platinum based) at elevated temperatures in the range of 500-900 degree F in the exhaust stack to create an intermediate chemical reaction to disassociate the CO & VOC molecules and reduce the CO & VOC emissions.

3. PUC quality natural gas.

VOC Emissions Control Technologies

a. $SCONO_X$™
b. CO/VOC Oxidation Catalysts
c. PUC quality natural gas

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

3. Top-Down BACT Analysis (Continued):

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

In order to determine the control efficiency of a given control method, the industry standard must first be determined. The industry standard is typically established as the industrywide average baseline emission rate for the device in question.

As detailed in the NO_X Top-Down BACT Analysis, the industry standard for VOC emissions was determined based upon information from various turbine manufacturers, therefore the District will consider the value of 6.25 ppmv (0.008 lb/MMBtu) as industry standard for this class and category of source.

Therefore, the proposed emissions from the gas turbines using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.008 \text{ lb}}{\text{MMBtu}} \left| \frac{3{,}676{,}800 \text{ MMBtu}}{\text{year}} \right. = 29{,}414 \text{ lb VOC/year}$$

(6.25 ppmv @ 15% O_2 = 0.008 lb/MMBtu)

PE_{VOC} = *29,414 lb VOC/year = 14.7 tons VOC/year*

As discussed in the NO_X Top-Down BACT section of this evaluation, the District will assume a 90% VOC control efficiency for the installation of a $SCONO_X$ system. The industry standard turbine VOC emissions using a $SCONO_X$ system is:

VOC (annual):

$$\frac{29{,}414 \text{ lb VOC}}{\text{year}} \left| \frac{(1-90\%)}{1} \right. = 2{,}941 \text{ lb VOC/year}$$

PE_{VOC} = *2,941 lb VOC/year = 1.5 tons VOC/year*

The District will assume a 71% VOC control efficiency (as stated on BACT guideline 3.4.4) for the installation of an oxidation catalyst. The industry standard turbine VOC emissions using an oxidation catalyst is:

VOC (annual):

$$\frac{29{,}414 \text{ lb VOC}}{\text{year}} \left| \frac{(1-71\%)}{1} \right. = 8{,}530 \text{ lb VOC/year}$$

PE_{VOC} = *8,530 lb VOC/year = 4.3 tons VOC/year*

3. Top-Down BACT Analysis (Continued):

Control Method	Industry Standard Emissions		Controlled Emissions		Overall Control efficiency
	lb/year	ton/year	lb/year	ton/year	
a. $SCONO_X$	29,414	14.71	2,941	1.47	90%
b. CO/VOC Oxidation Catalyst	29,414	14.71	8,530	4.27	71%
c. Natural gas	29,414	14.71	29,414	14.71	0%

VOC Emission Control Technology Rankings

Rank	Control Efficiency
#1. $SCONO_X$ System	90%
#2. CO/VOC Oxidation Catalyst	71%
#3. Natural gas	0%

Step 4 - <u>Cost Effectiveness Analysis</u>

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for VOC reduction is $5,000 per ton of VOC reduced.

1. VOC Cost Effectiveness Analysis:
$SCONO_X$ System

As demonstrated in the NO_X Top-Down BACT analysis, the $SCONO_X$ technology is not a cost effective technology. Therefore, this control technology will be removed from consideration.

2. VOC Cost Effectiveness Analysis:
Oxidation Catalyst

The applicant is proposing to utilize an oxidation catalyst to control VOC emissions. Since this control technology is the most effective VOC control technology listed in Step 3, a cost effectiveness analysis is not required.

Step 5 - <u>Select BACT</u>

The applicant has proposed to utilize option #2 (Oxidation Catalyst) as the VOC control technology. Therefore BACT for the emission unit is determined to be a turbine equipped with an oxidation catalyst.

3. Top-Down BACT Analysis (Continued):

C. PM_{10} Top-Down BACT Analysis for Permits (C-3929-1-0 & -2-0)

According to BACT guideline 3.4.8 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for PM_{10} emissions from similar operations.

Step 1 - <u>Identify All Possible Control Technologies</u>

General control for PM_{10} emissions include the following options:

1. Air inlet filter, lube oil vent coalescer (or equivalent), and PUC regulated natural gas fuel (1.0 gr-S/100 dscf) – specified as achieved-in-practice BACT in District Clearinghouse BACT Guideline 3.4.2.

2. PUC regulated natural gas fuel (1.0 gr-S/100 dscf) – specified as achieved in practice BACT in the California Air Resources Board's September 1999 <u>Guidance for Power Plant Siting and Best Available Control Technology</u> document (for turbines ≥ 50 MW).

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

All of the listed controls are considered technologically feasible for this application.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

1. Air inlet cooler/filter, lube oil vent coalescer (or equivalent), and PUC regulated natural gas fuel (1.0 gr-S/100 dscf).

2. PUC regulated natural gas fuel (1.0 gr-S/100 dscf).

Step 4 - <u>Cost Effectiveness Analysis</u>

The applicant is proposing to use an air inlet cooler/filter, lube oil vent coalescer (or equivalent), and PUC regulated natural gas fuel (1.0 gr-S/100 dscf). This is the highest ranking technologically feasible option, therefore a cost effective analysis will not be necessary.

Step 5 - <u>Select BACT</u>

The applicant has proposed to utilize option #1 as the PM_{10} control technology (Air inlet cooler/filter, lube oil vent coalescer (or equivalent), and PUC regulated natural gas fuel (1.0 gr-S/100 dscf). Therefore, BACT for this class of source is satisfied.

3. Top-Down BACT Analysis (Continued):

D. SO_X Top-Down BACT Analysis for Permits (C-3929-1-0 & -2-0)

According to BACT guideline 3.4.8 (Simple Cycle Gas Fired Turbines < 50 MW Powering an Electrical Generation Operation), the following are possible controls for PM_{10} emissions from similar operations.

Step 1 - Identify All Possible Control Technologies

General control for SO_X emissions include the following options:

1. PUC regulated natural gas fuel (1.0 gr-S/100 dscf) – specified as achieved in practice BACT in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document (for turbines ≥ 50 MW).

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC regulated natural gas fuel (1.0 gr-S/100 dscf).

Step 4 - Cost Effectiveness Analysis

The facility has proposed to use utility grade natural gas with a sulfur content of less than or equal to 0.25 grains per 100 dscf. Since this is the most effective control option, a cost effectiveness analysis is not required.

Step 5 - Select BACT

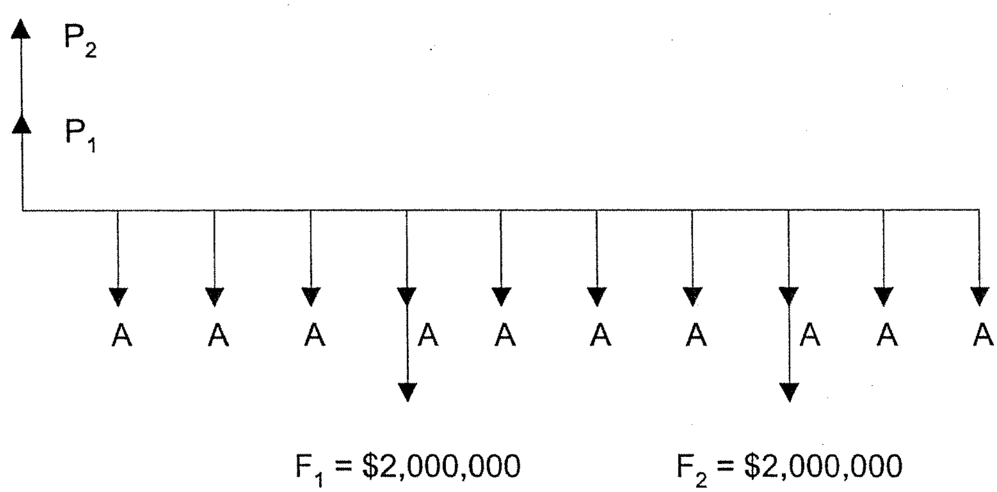
The applicant has proposed to use PUC quality natural gas with a sulfur content of less than or equal to 0.25 grains per 100 dscf as the SO_X control technology. Therefore, BACT for this class of source is satisfied.

APPENDIX I

CALCULATION OF ANNUAL COST FOR SCONO$_X$ CATALYST REPLACEMENT

Calculation of an Equivalent Annual Cost of the $SCONO_X$ catalyst replacement:

According to Goal Line Environmental Technologies, the $SCONO_X$ catalyst has a life span of approximately three to five years. Therefore, it is assumed that, on average, the catalyst must be replaced two times during the ten year life span. Information from the BACT determination performed for Southern region project #990210 (the most recent revision of guideline 3.4.2, which was approved in Q1, 2000) indicates that the replacement cost of a $SCONO_X$ catalyst is approximately 50% of the original system cost. Therefore, the applicant must purchase a new catalyst bed at $4,000,000 × 0.5 = $2,000,000 every four years. These future costs must be converted to an equivalent annual cost over the ten year life span, as illustrated below:



Step 1:
Each future cost (F_1, F_2) will be converted to a present worth value (P_1, P_2) assuming an interest rate of 10% and a 10 year life span using the following single payment present worth equation:

$$P = F \times \left[\frac{1}{(1+i)^n}\right]$$

where:
P = present worth
F = future cost
i = interest rate
n = life span

$$P_1 = \$2{,}000{,}000 \times \left[\frac{1}{(1+0.1)^4}\right] = \$1{,}366{,}027$$

$$P_2 = \$2{,}000{,}000 \times \left[\frac{1}{(1+0.1)^8}\right] = \$933{,}015$$

Step 2:
The total present worth value (P_1 + P_2) will be converted to an equivalent annual cost (A) assuming an interest rate of 10% and a 10 year life span using the following capital recovery equation:

$$A = P \times \left[\frac{i \times (1+i)^n}{(1+i)^n - 1}\right]$$

where:

P = present worth
A = equivalent annual cost
i = interest rate
n = life span

$$A = (\$1{,}366{,}027 + \$933{,}015) \times \left[\frac{0.1 \times (1+0.1)^{10}}{(1+0.1)^{10} - 1}\right] = \$374{,}054/\mathit{year}$$

ATTACHMENT E

TOP DOWN BACT ANALYSIS (C-3929-3-0)

1. BACT Applicability:

Pursuant to Sections 4.1.1 and 4.1.2, BACT shall be applied to a new, relocated, or modified emissions unit if the new or relocated unit has a Potential to Emit (PE) exceeding two pounds in any one day or the modified emissions unit results in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2 lb/day for NO_X, CO, VOC, PM_{10}, or SO_X. For CO emissions, the CO Post-project Stationary Source Potential to Emit (SSPE2) must also exceed 200,000 lb/year to trigger BACT.

As seen in Section VII.D of this evaluation, the applicant is proposing to install a new emissions unit with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day, but BACT is not triggered for CO emissions since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.E.2 of this document.

2. BACT Guidance:

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule. BACT Guideline 3.1.2, which appears in Attachment C of this report, covers diesel-fired emergency IC engines greater than or equal to 175 hp and less than 400 hp.

3. Top-Down BACT Analysis:

A. NO_X Top-Down BACT Analysis for Permit (C-3929-3-0):

Oxides of nitrogen (NO_X) are generated from the high temperature combustion of the diesel fuel. A majority of the NO_X emissions are formed from the high temperature reaction of nitrogen and oxygen in the inlet air. The rest of the NO_X emissions are formed from the reaction of fuel-bound nitrogen with oxygen in the inlet air.

Step 1 - <u>Identify All Possible NO_X Control Technologies</u>

The SJVAPCD BACT Clearinghouse identifies achieved-in-practice BACT for this engine as certified NO_X emissions of 6.9 g/hp-hr or less. No technologically feasible alternatives are listed.

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

There are no technologically feasible options listed.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

Certified NO_X emissions of 6.9 g/hp-hr or less.

3. Top-Down BACT Analysis (Continued):

Step 4 - Cost Effectiveness Analysis

The only control technology alternative in the ranking list from Step 3 has been achieved in practice. Therefore, per SJVAPCD BACT policy, the cost effectiveness analysis is not required.

Step 5 - Select BACT

Therefore, BACT for NO_X emissions is certified NO_X emissions of less than 6.9 g/hp·hr. The proposed IC engine is certified with NO_X emissions of 5.09 g/hp·hr, therefore BACT is satisfied

B. VOC Top-Down BACT Analysis for Permit (C-3929-3-0):

Volatile organic compounds result from the incomplete combustion of diesel fuel and are emitted from the crankcase of the engine as a result of piston ring blow-by.

Step 1 - Identify All Possible VOC Control Technologies

The SJVAPCD BACT Clearinghouse identifies achieved-in-practice BACT for this engine as positive crankcase ventilation (PCV).

Step 2 - Eliminate Technologically Infeasible Options

There are no technologically feasible options.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PCV

Step 4 - Cost Effectiveness Analysis

Since the only control technology alternative in the ranking list from Step 3 has been achieved in practice, a cost effectiveness analysis is not required.

Step 5 - Select BACT

BACT for VOC emissions for this engine is a PCV system.

C. PM_{10} Top-Down BACT Analysis for Permit (C-3929-3-0):

Particulate matter (PM_{10}) emissions occur from the reaction of various elements in the diesel fuel including fuel sulfur.

3. Top-Down BACT Analysis (Continued):

Step 1 - Identify All Possible PM_{10} Control Technologies

The SJVUAPCD BACT Clearinghouse identifies achieved-in-practice BACT for this engine as: 0.1 grams/bhp-hr (if TBACT is triggered) and 0.4 grams/bhp-hr (if TBACT is not triggered). In this case, TBACT is not triggered.

Step 2 - Eliminate Technologically Infeasible Options

There are no technologically feasible options.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

PM_{10} emissions of 0.1 grams/bhp-hr (if TBACT is triggered) and 0.4 grams/bhp-hr (if TBACT is not triggered).

Step 4 - Cost Effectiveness Analysis

The only control technology alternative in the ranking list from Step 3 has been achieved in practice. Therefore, per SJVAPCD BACT policy, the cost effectiveness analysis is not required.

Step 5 - Select BACT

BACT for PM_{10} emissions for this engine is PM_{10} emissions of less than or equal to 0.4 g/hp·hr.

D. SO_X Top-Down BACT Analysis for Permit (C-3929-3-0):

Oxides of sulfur (SO_X) emissions occur from the combustion of the sulfur which is present in the diesel fuel.

Step 1 - Identify All Possible SO_X Control Technologies

The SJVAPCD BACT Clearinghouse Guideline identifies achieved-in-practice BACT for this engine as low-sulfur fuel (0.05% by weight) or very low-sulfur fuel (0.0015% by weight) where available.

Step 2 - Eliminate Technologically Infeasible Options

There are no technologically feasible options.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

low-sulfur fuel or very low-sulfur fuel

3. Top-Down BACT Analysis (Continued):

Step 4 - Cost Effectiveness Analysis

The only control technology alternative in the ranking list from Step 3 has been achieved in practice. Therefore, per SJVAPCD BACT policy, the cost effectiveness analysis is not required.

Step 5 - Select BACT

BACT for SO_X emissions for this engine is the use of fuel with a sulfur content of 0.05% or 0.0015% where available.

ATTACHMENT F

Ambient Air Quality Modeling Summary Sheet

San Joaquin Valley Unified
Air Pollution Control District

MEMORANDUM

DATE: September 4, 2001

TO: Errol Villegas, AQE—Permit Services

FROM: Brian Clerico, AQS—Technical Services

SUBJECT: Ambient Air Quality Analysis and RMR Modeling Results for GWF Energy (C-3929)

As per your request, Technical Service performed a RMR and Ambient Air Quality Analysis on a 93.8 MW peaking power plant powered by two GE model LM-6000 PC Sprint simple-cycle natural gas fired turbines (1-0 and 2-0) each equipped with water injection, a selective catalytic reduction system, and an oxidation catalyst. Also in the proposal is a 397 hp emergency-fired diesel ICE (3-0) powering a 250 kW generator.

RMR Modeling

1995 Ventura County Emission Factors for turbine natural gas combustion were used to speciate and quantify the emissions. The emissions also include 6.25 lb/hr and 50,005 lb/ year of ammonia from the SCR system. Pollutant dispersion was determined from ISCST3 using the stack parameters provided by the engineer and building downwash data supplied by the applicant. The closest receptor is a work site at 1126m. To calculate chronic and cancer risks, the maximum annual X/Q from the entire receptor grid was used because this maximum value occurs at ~2200m from the fence-line, which is beyond the given receptor. By coincidence, each device has its maximum annual X/Q at the same point on the receptor grid. To calculate acute risks, the largest 1-hr X/Q for the turbines at 1000m from the fence-line was used.

Device	Natural Gas Turbine 1-0	Natural Gas Turbine 2-0	Emergency Diesel ICE	Project Total
Acute Index	**0.02**	**0.02**	N/A	**0.04**
Chronic Index	**0.00**	**0.00**	N/A	**0.00**
Cancer Risk (per million)	**0.0**	**0.0**	**0.1**	**0.1**
TBACT Required?	**No**	**No**	**No**	

AAQA

For the Ambient Air Quality Analysis, the engineer supplied the emission rates for each criteria pollutant on an hourly and annual basis. Background concentrations for the pollutants were drawn from EPA data for Hanford (2000 data for NO_x, PM_{10}) and Fresno County (2000 data for CO, 1997 for SO_x). Pollutant dispersion was determined from ISCST3 using the stack parameters provided by the engineer and building downwash data supplied by the applicant.

The ozone-limiting method was used to determine the maximum 1-hour NO_2 concentration. The results from the AAQA are as follows:

AAQA*

	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	**Pass**	X	**Pass**	X	X
NO_x	**Pass*** **	X	X	X	**Pass**
SO_x	**Pass**	**Pass**	X	**Pass**	**Pass**
PM_{10}	X	X	X	**Pass****	**Pass****

* See the attached PSD spreadsheet for pollutant concentrations.
** The PM_{10} emissions for this project are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
*** As determined by the Ozone-Limiting Method.
X = Not a designated averaging time for this pollutant.

Conclusion

The AAQA indicates that the emissions from the proposed equipment will not have an adverse impact on the State and National AAQS.

The acute and chronic indices are not above 1.0, and the cancer risk is not above 1.0 per million; therefore, in accordance with the District's RMR policy, **the project is approved for permitting without TBACT.**

RO Time: 8.0 hours

ATTACHMENT G

Interpollutant Offset Ratio Analysis

sierra
research

1801 J Street
Sacramento, CA 95814
(916) 444-6666
Fax: (916) 444-8373

August 8, 2001

Memo To: Doug Wheeler
GWF Power Systems Company

From: David Deckman

Subject: Interpollutant Offset Ratio Analysis for GWF Henrietta Project

As you requested, attached is an analysis of the interpollutant offset ratio for using sulfur oxides (SOx) Emission Reduction Credits to offset emissions of respirable particulate matter (PM_{10}). GWF Energy LLC is proposing to use SOx ERCs, which were generated from the shutdown of a facility in Hanford, to offset PM_{10} from the proposed Henrietta Peaker Plant (HPP). The distance between the source of the ERCs and the proposed power plant project is 16.2 miles. Our analysis indicates that the appropriate interpollutant ratio is 1.4 to 1.0, and that the overall offset ratio, including the adjustment for distance between the proposed project and the source of the ERCs, would be 1.9 to 1.0. This analysis is consistent with those approved by the San Joaquin Valley Unified Air Pollution Control District for other projects.

Please be aware that Section 4.2.5.3 of SJVUAPCD Rule 2201 (New and Modified Stationary Source Review) allows the use of interpollutant offsets only if the project will not cause violations of the ambient air quality standards. Because ambient PM_{10} concentrations in the San Joaquin Valley currently exceed the state and federal standards, the SJVUAPCD is accepting a demonstration that the project would not cause PM_{10} ambient concentrations in excess of the significance criteria in Title 40 Code of Federal Regulations Part 51.165(b)(2). These thresholds are 5 micrograms per cubic meter ($\mu g/m^3$) and 1.0 $\mu g/m^3$ for the 24-hour and annual averaging periods, respectively. The air quality impact analysis and modeling will be prepared and submitted as part of the Application for Certification for this project.

If you have any questions regarding this analysis, please feel free to contact us.

attachment

INTERPOLLUTANT OFFSET RATIO ANALYSIS FOR THE GWF ENERGY LLC HENRIETTA PEAKER PLANT

GWF Energy LLC (GWF) proposes to use sulfur oxides (SOx) Emission Reduction Credits (ERCs) to offset emissions of respirable particulate matter (PM_{10}) from its proposed Henrietta Peaker Plant in Kings County, California. The SOx ERCs will supplement PM_{10} ERCs from Certificate No. C-366-4. GWF also owns SOx ERC Certificate Nos. N-414-5 and N-415-5. The two SOx ERC certificates were issued by the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) for emission reductions that were originally generated by the shutdown of a facility located at 525 West Third Street in Hanford, California. SJVUAPCD Rule 2201, Section 4.2.5.3 provides:

> *Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, in accordance with the provisions of Section 4.3.2 of this rule, that the emission increases from the new or modified source will not cause or contribute to a violation of an ambient air quality standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements, of this rule.*

GWF will provide a demonstration that the emission increases associated with the project will not cause or contribute to a violation of an ambient air quality standard. This analysis does not address those impacts.

This analysis provides a technical rationale for an appropriate SOx-to-PM_{10} interpollutant ratio, as well as the overall offset ratio to reflect the distance between the source providing the offsets and the proposed project.

Interpollutant Ratio

To develop an interpollutant offset ratio for SOx and PM_{10}, this analysis uses (1) a speciated linear rollback analysis using ambient monitoring data from Kings County, in which both the proposed GWF project and the ERC source are located; (2) emission inventory data in Kings County; and (3) the results of Chemical Mass Balance (CMB) modeling at a location in Kings County. The approach is based on a simple box model that ignores transport and deposition; assumes that the box is the size of Kings County; and assumes that the ambient pollutant concentrations in the box (Kings County) can be represented by the values reported for the South Irwin Street monitoring station in Hanford and the Patterson Avenue and Van Dorsten Avenue monitoring stations in Corcoran. These are the only monitoring stations in Kings County that have the data required for this analysis. The interpollutant ratio calculations described below are shown in Attachment 1.

The actual, annual average nitrate, sulfate, chloride, and total PM_{10} ambient air measurements were used to partially speciate the PM_{10}. The ambient monitoring data were reported by the Air Resources Board (ARB) for monitoring stations located on South Irwin Street in Hanford and on Patterson Avenue and Van Dorsten Avenue in Corcoran for 1997 and 1998, the most recent years for which the speciated PM_{10} were available. According to ARB staff, speciation of the PM_{10} samples was discontinued at these monitoring stations at the end of 1998.

The unspeciated balance of the PM_{10} (after subtracting the ammonium sulfate, ammonium nitrate, and ammonium chloride from total PM_{10}) is split between direct-combustion-related PM_{10} (fuel combustion and mobile sources) and other direct PM_{10} sources. The contribution from direct-combustion-related PM_{10} is based on Chemical Mass Balance (CMB) modeling performed for the District's PM_{10} Attainment Demonstration Plan. CMB modeling was conducted by the ARB for several locations within the San Joaquin Valley for annual average conditions in support of the District's attainment plan. Annual analyses were performed for locations in Bakersfield, Corcoran, Fresno, and Visalia. The nearest modeled site to the proposed GWF project is Corcoran. The CMB modeling evaluated the contribution of specific source categories. The "mobile" category represents the contribution from mobile and other combustion sources, such as those proposed for the GWF project. In this case, the CMB modeling for the Corcoran location found that the mobile category contributed 5.39 micrograms per cubic meter ($\mu g/m^3$) out of the total annual average PM_{10} concentration of 59 $\mu g/m^3$ for 1993. A table from the attainment plan showing these values is attached (see Attachment 2). Thus, the direct-combustion contribution was assumed to be 9.1 percent (i.e., 5.39/59).

Next, since direct PM_{10} emissions from combustion sources (gas turbines) are being offset, it was determined how many $\mu g/m^3$ of ambient PM_{10} are associated with 1 ton/year of direct combustion PM_{10} emissions by dividing the annual average direct-combustion PM_{10} concentration by the total annual PM_{10} emissions in Kings County. A similar calculation was performed for sulfur dioxide by dividing the annual average sulfate concentration by the annual SO_2 emissions in Kings County. The inventory data were obtained from the ARB website (http://www.arb.ca.gov/app/emsinv/emssumcat.php). The daily values from this inventory were multiplied by 365 to compute the annual values. Total PM_{10} and SOx inventories were calculated for the years considered in this analysis. Inventory data were available from the ARB website for 1996 and 1998, but not for 1997. The 1997 inventory was computed by interpolating between 1996 and 1997. The inventory data for Kings County are shown in Attachment 3. The ratio of the $\mu g/m^3$ per ton/year values indicates the number of tons of sulfur dioxide emissions that it takes to create the same number of $\mu g/m^3$ of PM_{10} that would be created by 1 ton/year of direct-combustion PM_{10} emissions. As shown in Attachment 1, this calculation results in interpollutant offset ratios of 1.17 to 1 and 1.64 to 1 for the two years evaluated, or an average of 1.4 to 1. The results were relatively consistent between the three monitoring stations for each year, and differ slightly between the two calendar years of data on which these analyses were based.

Offset Ratio

Rule 2201 does not indicate specifically how the interpollutant ratio (described above) and the distance ratio (pursuant to Section 4.2.4 of Rule 2201) should be applied. Leonard Scandura of the District's Southern Region office provided a description of how the District computes the overall offset ratio. The methodology provided by Mr. Scandura addresses sources of NOx offsets within 15 miles of the new source and more than
15 miles from the new source. Because the ERC source in this case is more than 15 miles from the GWF facility and is providing SOx ERCs, this description has been modified to address only this case. The methodology provided by Mr. Scandura is as follows (with revisions to reflect the distance relationship, transfer of SOx ERCs, and a 1.4 to 1 interpollutant offset ratio):

> *Rule 2201 includes provisions for including distance offset ratios and interpollutant offset ratios to determine the quantity of offsets required. These two offset ratios are applied independently to determine the quantity of offset required.*
>
> *The distance ratio specifies the excess amount of offsets required due to the distance between the increase in emissions and the location at which the emission reductions occurred. For example, if the distance offset ratio is 1.5:1, 100% of the fraction of the emission increase to be offset at this distance is required plus an additional 50% to account for the distance between the increase in emissions and the location of the emissions reductions.*
>
> *The interpollutant offset ratio specifies excess amount of offsets required when the emission increases and the offsets being provided are not the same pollutant. Specifically, the interpollutant offset ratio quantifies the relationship between the pollutant being emitted and the emission reductions being provided. In this case [the analysis described in this report], the interpollutant offset ratio is 1.4:1, i.e., 100% of the emission increase is required to be offset plus an additional 40% to account for the relationship between the pollutant being emitted and the emissions reduction.*
>
> *When both the distance and interpollutant offset ratios apply, the overall offset quantity required is equal to the sum of the amount being emitted and the excess amount(s) required due to the distance offset ratio plus the excess amount due to the interpollutant offset ratio. The computation of the resulting overall SOx for PM_{10} offset ratio is as follows:*
>
> *SOx req'd ton/year = PM_{10} ton/year + PM_{10} ton/year to be offset by SOx ERCs >15 miles away * 0.5 + PM_{10} ton/year to be offset by SOx reductions * 0.4*
>
> *SOx req'd ton/year =PM_{10} ton/year + PM_{10} ton/year (0.5) + PM_{10} ton/year (0.4)*
>
> *SOx req'd ton/year = PM_{10} ton/year (1 + 0.5 + 0.4)*

Thus, the combined distance and interpollutant ratio is:

$SOx/PM10 = 1 + 0.5 + 0.4$

Using this methodology, the overall distance and interpollutant offset ratio is as follows:

$SOx/PM_{10} = 1 + 0.5 + 0.4 = 1.9$

ATTACHMENT 1

INTERPOLLUTANT OFFSET RATIO CALCULATIONS

GWF - Henrietta Peaker Plant
PM10 Interpollutant Offset Ratio Analysis

07-Aug-01

1997 Annual Average Concentrations (AAM)

Station	Total PM10 ug/m3	PM10 Nitrate ug/m3	PM10 Sulfate ug/m3	PM10 Chloride ug/m3
Hanford - So Irwin St	46.5	5.42	1.79	0.046
Corcoran - Patterson	48.1	4.89	1.66	0.061
Corcoran - VanDorsten	44.8	5.24	1.62	0.052
Ion Form		NO3	SO4	Cl
Ion Molecular Weight		62.005	96.062	35.453
Combined Form		NH4NO3	(NH4)2SO4	NH4Cl
Combined Molecular Wt		80.043	132.139	53.492

Direct Combustion PM10 fraction of total ambient PM10 (source apportionment): 9.1%

Station	Total PM10 ug/m3	PM10 NH4NO3 ug/m3	PM10 (NH4)2SO4 ug/m3	PM10 NH4Cl ug/m3	PM10 Direct Combustion ug/m3	PM10 Other ug/m3
Hanford - So Irwin St	46.5	7.00	2.46	0.07	4.23	32.74
Corcoran - Patterson	48.1	6.31	2.28	0.09	4.38	35.03
Corcoran - VanDorsten	44.8	6.76	2.23	0.08	4.08	31.65

1997 Annual Emissions (tons/year) - Kings County

Total PM10	NOx	SOx	Combustion PM10	Other Direct PM10
13,291	9,769	529	588	12,704

		Hanford So Irwin St	Corcoran Patterson	Corcoran VanDorsten	Average
Direct Combustion PM10:					
588	tons/yr =	4.23	4.38	4.08	
1	ton/yr =	0.00720	0.00745	0.00694	
SO2 -> Sulfates:					
529	tons/yr =	2.46	2.28	2.23	
1	ton/yr =	0.00465	0.00431	0.00421	
SO2:PM10 ratio =		1.55	1.73	1.65	1.64

GWF - Henrietta Peaker Plant

07-Aug-01

PM10 Interpollutant Offset Ratio Analysis

1998 Annual Average Concentrations (AAM)

Station	Total PM10 ug/m3	PM10 Nitrate ug/m3	PM10 Sulfate ug/m3	PM10 Chloride ug/m3
Hanford - So Irwin St	38.9	3.33	2.00	0.028
Corcoran - Patterson	38.2	4.08	1.86	0.031
Corcoran - VanDorsten	29.0	1.30	1.74	0.027
Ion Form		NO3	SO4	Cl
Ion Molecular Weight		62.005	96.062	35.453
Combined Form		NH4NO3	(NH4)2SO4	NH4Cl
Combined Molecular Wt		80.043	132.139	53.492

Direct Combustion PM10 fraction of total ambient PM10 (source apportionment): 9.1%

Station	Total PM10 ug/m3	PM10 NH4NO3 ug/m3	PM10 (NH4)2SO4 ug/m3	PM10 NH4Cl ug/m3	PM10 Direct Combustion ug/m3	PM10 Other ug/m3
Hanford - So Irwin St	38.9	4.30	2.75	0.04	3.54	28.27
Corcoran - Patterson	38.2	5.27	2.56	0.05	3.48	26.85
Corcoran - VanDorsten	29.0	1.68	2.39	0.04	2.64	22.25

1998 Annual Emissions (tons/year) - Kings County

Total PM10	NOx	SOx	Combustion PM10	Other Direct PM10
13,363	9,815	533	569	12,793

		Hanford So Irwin St	Corcoran Patterson	Corcoran VanDorsten	Average
Direct Combustion PM10:					
	569 tons/yr =	3.54	3.48	2.64	
	1 ton/yr =	0.00622	0.00611	0.00463	
SO2 -> Sulfates:					
	533 tons/yr =	2.75	2.56	2.39	
	1 ton/yr =	0.00516	0.00480	0.004491	
SO2:PM10 ratio =		1.20	1.27	1.03	1.17

ATTACHMENT 2

CMB MODELING RESULTS FOR CORCORAN

CORCORAN	TOTAL	Geologic	Construction	Mobile	Organic Carbon	Vegetative Burning	Ammonium Nitrate	Associated Water	Ammonium Sulfate	Unassigned	Marine
CMB Annual	59.00	32.44	0.35	5.39	0.00	0.70	7.41	2.00	2.32	8.09	0.30
CMB Percents		54.98%	0.59%	9.13%	0.00%	1.19%	12.56%	3.39%	3.93%	13.71%	0.52%
Adjusted Concentrations	52.00	28.59	0.31	4.75	0.00	0.62	6.53	1.76	2.04	7.13	0.27
Natural Background %		5%	0%	0%	0%	0%	0%	0%	0%	10%	100%
Natural Background Value	2.41	1.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.71	0.27
Local Contribution (Adjusted Concentration - Background)	49.59	27.16	0.31	4.75	0.00	0.62	6.53	1.76	2.04	6.42	0.00
Ammonia Emission Estimate (%)							15%				
Ammonia Emission Estimate (ug/m3)	0.98						0.98				
Local Contribution (Without Ammonia)	48.61	27.16	0.31	4.75	0.00	0.62	5.55	1.76	2.04	6.42	0.00
Base Year 1993 Emission Inventory PM10	457.80	378.22	18.45	16.54		36.82				457.80	
ROG	538.87				538.87						
NOx	578.14						578.14	578.14			
SOx	34.88								34.88		
Future Year Emission Inventory 2001 PM	435.27	340.93	14.80	9.98		56.05				435.27	
ROG	387.58				387.58						
NOx	456.87						456.87	456.87			
SOx	33.70								33.70		
Ef/Eb Ratio for Local Rollback Projection	0.81	0.90	0.80	0.60	0.72	1.52	0.79	0.79	0.97	0.95	1.00
Projected Local	42.39	24.48	0.25	2.86	0.00	0.94	4.39	1.39	1.97	6.10	0.00
Natural Background	2.41	1.43	0.00	0.00	0.00	0:00	0.00	0.00	0.00	0.71	0.27
Ammonia Emission Estimate	0.98						0.98				
2001 Projected Annual (Result)	45.78	25.91	0.25	2.86	0.00	0.94	5.37	1.39	1.97	6.81	0.27
Future Year Emission Inventory 2008 PM	446.21	348.57	16.26	9.71		58.28				446.21	
ROG	328.21				328.21						
NOx	402.95						402.95	402.95			
SOx	35.15								35.15		
Ef/Eb Ratio for Local Rollback Projection	0.75	0.92	0.88	0.59	0.61	1.58	0.70	0.70	1.01	0.97	1.00
Projected Local	42.48	25.03	0.27	2.79	0.00	0.98	3.87	1.23	2.06	6.25	0.00
Natural Background	2.41	1.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.71	0.27
Ammonia Emission Estimate	0.98						0.98				
2008 Projected Annual (Result)	45.87	26.46	0.27	2.79	0.00	0.98	4.85	1.23	2.06	6.97	0.27

ATTACHMENT 3

EMISSIONS INVENTORY
FOR
KINGS COUNTY

1997 EMISSION INVENTORY FOR KINGS COUNTY

CATEGORY	SUBCATEGORY	EMISSIONS (TONS PER DAY) TOG	ROG	CO	NOX	SOX	PM	PM10
FUEL COMBUSTION	ELECTRIC UTILITIES	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMBUSTION	COGENERATION	0.02	0.00	0.07	0.08	0.19	0.02	0.01
FUEL COMBUSTION	OIL AND GAS PRODUCTION (COMBUSTION)	0.21	0.02	0.08	0.54	0.01	0.01	0.01
FUEL COMBUSTION	PETROLEUM REFINING (COMBUSTION)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMBUSTION	MANUFACTURING AND INDUSTRIAL	0.04	0.01	0.63	5.24	0.22	0.11	0.09
FUEL COMBUSTION	FOOD AND AGRICULTURAL PROCESSING	0.21	0.18	1.11	3.68	0.33	0.39	0.37
FUEL COMBUSTION	SERVICE AND COMMERCIAL	0.03	0.02	0.30	1.32	0.03	0.04	0.04
FUEL COMBUSTION	OTHER (FUEL COMBUSTION)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	SEWAGE TREATMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	LANDFILLS	0.03	0.02	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	INCINERATORS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	SOIL REMEDIATION	0.02	0.01	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	OTHER (WASTE DISPOSAL)	2.18	1.06	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	LAUNDERING	0.02	0.00	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	DEGREASING	0.31	0.28	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	COATINGS AND RELATED PROCESS SOLVENTS	0.42	0.39	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	PRINTING	0.03	0.03	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	ADHESIVES AND SEALANTS	0.06	0.05	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	OTHER (CLEANING AND SURFACE COATINGS)	0.02	0.00	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	OIL AND GAS PRODUCTION	0.73	0.41	0.00	0.01	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM REFINING	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM MARKETING	0.18	0.17	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	OTHER (PETROLEUM PRODUCTION AND MARKETING)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	CHEMICAL	0.15	0.13	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	FOOD AND AGRICULTURE	1.24	0.75	0.00	0.00	0.00	1.78	0.98
INDUSTRIAL PROCESSES	MINERAL PROCESSES	0.00	0.00	0.00	0.00	0.00	0.13	0.08
INDUSTRIAL PROCESSES	METAL PROCESSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	WOOD AND PAPER	0.00	0.00	0.00	0.00	0.00	0.01	0.01
INDUSTRIAL PROCESSES	GLASS AND RELATED PRODUCTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	ELECTRONICS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	OTHER (INDUSTRIAL PROCESSES)	0.00	0.00	0.00	0.00	0.00	0.01	0.01
SOLVENT EVAPORATION	CONSUMER PRODUCTS	1.20	0.99	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS	0.44	0.42	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	PESTICIDES/FERTILIZERS	2.65	2.65	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	ASPHALT PAVING / ROOFING	0.08	0.07	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	REFRIGERANTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	OTHER (SOLVENT EVAPORATION)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MISCELLANEOUS PROCESSES	RESIDENTIAL FUEL COMBUSTION	0.31	0.13	1.77	0.09	0.00	0.30	0.28
MISCELLANEOUS PROCESSES	FARMING OPERATIONS	93.93	7.51	0.00	0.00	0.00	27.84	12.66
MISCELLANEOUS PROCESSES	CONSTRUCTION AND DEMOLITION	0.00	0.00	0.00	0.00	0.00	1.80	0.88
MISCELLANEOUS PROCESSES	PAVED ROAD DUST	0.00	0.00	0.00	0.00	0.00	4.18	1.91
MISCELLANEOUS PROCESSES	UNPAVED ROAD DUST	0.00	0.00	0.00	0.00	0.00	12.90	7.67
MISCELLANEOUS PROCESSES	FUGITIVE WINDBLOWN DUST	0.00	0.00	0.00	0.00	0.00	17.37	7.91
MISCELLANEOUS PROCESSES	FIRES	0.01	0.00	0.05	0.00	0.00	0.01	0.01
MISCELLANEOUS PROCESSES	WASTE BURNING AND DISPOSAL	2.94	1.68	18.64	0.18	0.00	2.70	2.65
MISCELLANEOUS PROCESSES	UTILITY EQUIPMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MISCELLANEOUS PROCESSES	COOKING	0.02	0.02	0.00	0.00	0.00	0.07	0.05

1997 EMISSION INVENTORY FOR KINGS COUNTY

CATEGORY	SUBCATEGORY	TOG	ROG	CO	NOX	SOX	PM	PM10
		EMISSIONS (TONS PER DAY)						
MISCELLANEOUS PROCESSES	OTHER (MISCELLANEOUS PROCESSES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT DUTY PASSENGER (LDA)	3.93	3.58	30.85	2.47	0.03	0.08	0.08
ON-ROAD MOTOR VEHICLES	LIGHT AND MEDIUM DUTY TRUCKS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 1 (LDT1)	1.31	1.20	12.95	0.92	0.01	0.02	0.02
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 2 (LDT2)	0.95	0.85	9.90	1.22	0.01	0.05	0.05
ON-ROAD MOTOR VEHICLES	MEDIUM DUTY TRUCKS (MDV)	0.99	0.90	10.39	0.91	0.01	0.03	0.03
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS TRUCKS (ALL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 1 (LHDV1)	0.61	0.56	9.41	0.40	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 2 (LHDV2)	0.03	0.02	0.30	0.05	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY GAS TRUCKS (MHDV)	0.45	0.41	7.86	0.25	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY GAS TRUCKS (HHDV)	0.21	0.19	3.86	0.09	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL TRUCKS (ALL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 1 (LHDV1)	0.00	0.00	0.01	0.03	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 2 (LHDV2)	0.00	0.00	0.01	0.06	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY DIESEL TRUCKS (MHDV)	0.04	0.03	0.23	0.65	0.02	0.03	0.03
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY DIESEL TRUCKS (HHDV)	0.30	0.26	1.27	2.49	0.08	0.13	0.13
ON-ROAD MOTOR VEHICLES	MOTORCYCLES (MCY)	0.11	0.10	0.42	0.02	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL URBAN BUSES (UB)	0.01	0.01	0.03	0.11	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS URBAN BUSES (UB)	0.00	0.00	0.10	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	SCHOOL BUSES (SB)	0.03	0.02	0.57	0.10	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MOTOR HOMES (MH)	0.03	0.03	0.48	0.07	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	OTHER (ON-ROAD MOTOR VEHICLES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	AIRCRAFT	3.84	3.42	7.88	0.96	0.00	0.21	0.21
OTHER MOBILE SOURCES	TRAINS	0.01	0.01	0.03	0.24	0.00	0.00	0.00
OTHER MOBILE SOURCES	SHIPS AND COMMERCIAL BOATS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	RECREATIONAL BOATS	0.05	0.05	0.16	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	OFF-ROAD RECREATIONAL VEHICLES	0.12	0.11	0.71	0.01	0.00	0.00	0.00
OTHER MOBILE SOURCES	OFF-ROAD EQUIPMENT	0.36	0.31	3.36	0.90	0.09	0.06	0.06
OTHER MOBILE SOURCES	FARM EQUIPMENT	0.56	0.50	3.32	3.74	0.44	0.24	0.24
OTHER MOBILE SOURCES	FUEL STORAGE AND HANDLING	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	OTHER (OTHER MOBILE SOURCES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	GEOGENIC SOURCES	0.01	0.01	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	WILDFIRES	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	WINDBLOWN DUST	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	OTHER (NATURAL SOURCES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALL SOURCES		121.33	29.49	126.67	26.77	1.45	70.47	36.42

PM10 - FUEL COMBUSTION	0.78
PM10 - MOBILE SOURCES	0.83
PM10 - ALL SOURCES	36.42

1998 EMISSION INVENTORY FOR KINGS COUNTY

CATEGORY	SUBCATEGORY	EMISSIONS (TONS PER DAY) TOG	ROG	CO	NOX	SOX	PM	PM10
FUEL COMBUSTION	ELECTRIC UTILITIES	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMBUSTION	COGENERATION	0.02	0.00	0.06	0.07	0.19	0.02	0.01
FUEL COMBUSTION	OIL AND GAS PRODUCTION (COMBUSTION)	0.24	0.02	0.09	0.63	0.01	0.01	0.01
FUEL COMBUSTION	PETROLEUM REFINING (COMBUSTION)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COMBUSTION	MANUFACTURING AND INDUSTRIAL	0.03	0.02	0.64	5.38	0.22	0.10	0.06
FUEL COMBUSTION	FOOD AND AGRICULTURAL PROCESSING	0.21	0.18	1.08	3.67	0.33	0.39	0.36
FUEL COMBUSTION	SERVICE AND COMMERCIAL	0.02	0.02	0.42	1.72	0.03	0.03	0.03
FUEL COMBUSTION	OTHER (FUEL COMBUSTION)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	SEWAGE TREATMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	LANDFILLS	0.06	0.04	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	INCINERATORS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	SOIL REMEDIATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	OTHER (WASTE DISPOSAL)	2.11	1.01	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	LAUNDERING	0.02	0.00	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	DEGREASING	0.32	0.29	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	COATINGS AND RELATED PROCESS SOLVENTS	0.38	0.36	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	PRINTING	0.03	0.03	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	ADHESIVES AND SEALANTS	0.05	0.04	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	OTHER (CLEANING AND SURFACE COATINGS)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	OIL AND GAS PRODUCTION	0.71	0.40	0.00	0.01	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM REFINING	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM MARKETING	0.17	0.17	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	OTHER (PETROLEUM PRODUCTION AND MARKETING)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	CHEMICAL	0.14	0.12	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	FOOD AND AGRICULTURE	1.16	0.94	0.00	0.00	0.00	1.76	1.01
INDUSTRIAL PROCESSES	MINERAL PROCESSES	0.00	0.00	0.00	0.00	0.00	0.13	0.09
INDUSTRIAL PROCESSES	METAL PROCESSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	WOOD AND PAPER	0.00	0.00	0.00	0.00	0.00	0.01	0.01
INDUSTRIAL PROCESSES	GLASS AND RELATED PRODUCTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	ELECTRONICS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	OTHER (INDUSTRIAL PROCESSES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	CONSUMER PRODUCTS	1.19	1.00	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS	0.45	0.43	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	PESTICIDES/FERTILIZERS	2.20	2.20	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	ASPHALT PAVING / ROOFING	0.08	0.07	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	REFRIGERANTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	OTHER (SOLVENT EVAPORATION)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MISCELLANEOUS PROCESSES	RESIDENTIAL FUEL COMBUSTION	0.31	0.13	1.75	0.09	0.00	0.29	0.27
MISCELLANEOUS PROCESSES	FARMING OPERATIONS	93.93	7.51	0.00	0.00	0.00	27.84	12.66
MISCELLANEOUS PROCESSES	CONSTRUCTION AND DEMOLITION	0.00	0.00	0.00	0.00	0.00	1.85	0.91
MISCELLANEOUS PROCESSES	PAVED ROAD DUST	0.00	0.00	0.00	0.00	0.00	4.26	1.95
MISCELLANEOUS PROCESSES	UNPAVED ROAD DUST	0.00	0.00	0.00	0.00	0.00	12.85	7.64
MISCELLANEOUS PROCESSES	FUGITIVE WINDBLOWN DUST	0.00	0.00	0.00	0.00	0.00	17.37	7.91
MISCELLANEOUS PROCESSES	FIRES	0.01	0.00	0.05	0.00	0.00	0.01	0.01
MISCELLANEOUS PROCESSES	WASTE BURNING AND DISPOSAL	3.09	1.76	19.67	0.18	0.00	2.86	2.81
MISCELLANEOUS PROCESSES	UTILITY EQUIPMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MISCELLANEOUS PROCESSES	COOKING	0.02	0.02	0.00	0.00	0.00	0.07	0.05

1998 EMISSION INVENTORY FOR KINGS COUNTY

CATEGORY	SUBCATEGORY	EMISSIONS (TONS PER DAY) TOG	ROG	CO	NOX	SOX	PM	PM10
MISCELLANEOUS PROCESSES	OTHER (MISCELLANEOUS PROCESSES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT DUTY PASSENGER (LDA)	3.71	3.37	29.09	2.37	0.03	0.08	0.08
ON-ROAD MOTOR VEHICLES	LIGHT AND MEDIUM DUTY TRUCKS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 1 (LDT1)	1.25	1.14	12.30	0.88	0.01	0.02	0.02
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 2 (LDT2)	0.94	0.83	9.56	1.22	0.01	0.05	0.05
ON-ROAD MOTOR VEHICLES	MEDIUM DUTY TRUCKS (MDV)	0.97	0.87	9.98	0.92	0.01	0.03	0.03
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS TRUCKS (ALL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 1 (LHDV1)	0.55	0.50	8.39	0.38	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 2 (LHDV2)	0.02	0.02	0.27	0.04	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY GAS TRUCKS (MHDV)	0.40	0.36	7.02	0.23	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY GAS TRUCKS (HHDV)	0.18	0.16	3.31	0.08	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL TRUCKS (ALL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 1 (LHDV1)	0.00	0.00	0.01	0.03	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 2 (LHDV2)	0.00	0.00	0.01	0.06	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY DIESEL TRUCKS (MHDV)	0.04	0.03	0.22	0.62	0.02	0.03	0.03
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY DIESEL TRUCKS (HHDV)	0.26	0.23	1.11	2.25	0.07	0.11	0.11
ON-ROAD MOTOR VEHICLES	MOTORCYCLES (MCY)	0.08	0.08	0.34	0.01	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL URBAN BUSES (UB)	0.01	0.01	0.03	0.11	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS URBAN BUSES (UB)	0.00	0.00	0.10	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	SCHOOL BUSES (SB)	0.02	0.02	0.50	0.10	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MOTOR HOMES (MH)	0.03	0.02	0.46	0.06	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	OTHER (ON-ROAD MOTOR VEHICLES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	AIRCRAFT	3.84	3.42	7.88	0.96	0.00	0.21	0.21
OTHER MOBILE SOURCES	TRAINS	0.01	0.01	0.03	0.23	0.00	0.00	0.00
OTHER MOBILE SOURCES	SHIPS AND COMMERCIAL BOATS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	RECREATIONAL BOATS	0.05	0.05	0.16	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	OFF-ROAD RECREATIONAL VEHICLES	0.12	0.11	0.68	0.01	0.00	0.00	0.00
OTHER MOBILE SOURCES	OFF-ROAD EQUIPMENT	0.35	0.30	3.34	0.90	0.09	0.06	0.06
OTHER MOBILE SOURCES	FARM EQUIPMENT	0.55	0.49	3.28	3.68	0.44	0.23	0.23
OTHER MOBILE SOURCES	FUEL STORAGE AND HANDLING	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	OTHER (OTHER MOBILE SOURCES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	GEOGENIC SOURCES	0.01	0.01	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	WILDFIRES	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	WINDBLOWN DUST	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	OTHER (NATURAL SOURCES)	0.00	0.00	0.00	0.00	0.00	0.00	36.61
ALL SOURCES		120.34	28.79	121.83	26.89	1.46	70.67	36.61

PM10 - FUEL COMBUSTION	0.74
PM10 - MOBILE SOURCES	0.82
PM10 - ALL SOURCES	36.61